AR88

Let us tell you how we create long-term shareholder value.

We have the discipline, the resourcefulness and the focus to achieve our long-term goals.

The people of TransAlta ensure our success.

HERE'S HOW WE DO IT.

TransAlta

TRANSALTA CORPORATION 2005 ANNUAL REPORT

EXPECT THE UNEXPECTED

Canadian and U.S. generally accepted accounting principles (GAAP) require us to deconsolidate our Mexican operations (see *Note 1R*, page 77). As a result, pages 31–115 exclude details of our Mexican operations. To get a view of the company including Mexico, read our discussion of the company from pages 1–30.

Acting Decisively as a Competitive Advantage

THE CALL CAME AT 5:30 A.M. A Canadian National Railway (CN) train had derailed at Lake Wabamun, Alberta, spilling oil into the lake. TransAlta employees acted immediately, volunteering with cleanup efforts and assessing any impact to the company's power plants. Oil could impair operations, making it impossible for TransAlta to generate power.

"We knew it was just a matter of time before the oil would reach our facilities," says Nick Oke, Environmental Specialist at TransAlta's Wabamun power plant. "With two of our plants using lake water for operations, we had some urgent decisions to make."

Within hours, TransAlta employees shut down the 279 megawatt (MW) Wabamun power plant to protect it from oil contamination.

Across the lake, the 2,020 MW Sundance power plant, which supplies about 20 per cent of the province's power, was still in jeopardy.

"We knew we had to do something to stop the oil from entering the Sundance plant," explains Oke. An existing canal normally served as both the intake location for the plant and also as the discharge point for the Wabamun Lake Water Treatment Plant. The engineers and operations teams considered building a weir across the mouth of the canal that would be two feet higher than lake elevation. This barrier would stop oil from entering the facility, and ensure the plant would have the clean water it needed to continue to operate. But prompt action was needed. TransAlta and its partner Luscar rallied people on the site. In just eight hours, 14 people moved 2,100 tonnes of soil and rock to build the weir.

This stronghold remains in operation today, protecting the Sundance power plant from residual oil and, ultimately protecting the province's power supply.

This wasn't the only unexpected challenge TransAlta people faced in 2005. A fire at the Suncor facility in Fort McMurray halted operations at our Poplar Creek plant. Mother Nature sent a different challenge our way with heavy rains and flooding in southern Alberta impacting hydro operations. Our people responded quickly and effectively in every situation.

Past performance is a pretty good indicator of how a company will perform in the future. We have the strategy and over 2,600 dedicated people like Nick Oke and Anita Stocker who work hard to ensure TransAlta continues to be a low-cost producer. TransAlta employees have the expertise to safeguard the company's assets and your investment. Our track record of operational excellence proves we can be counted on to produce power, no matter what challenges we face year after year.

(left) Nick Oke and Anita Stocker, Cycle Chemist, Wabamun Lake Water Treatment Plant, at the weir.

Campeche power plant

Day after day, we produce power for people in four different countries – Canada, the United States, Mexico and Australia.

In 2005, our plants were available

89.7%

of the time,

producing

54,561

gigawatt hours of electricity,

and generating approximately

$3.1 billion

in revenue.

FUEL TYPES

TransAlta fuels its plants from diverse sources. This protects the company from a sudden, unexpected increase in the cost of any one fuel or the unpredictable nature of water flows and wind.

58%
COAL

29%
GAS

9%
HYDRO

4%
RENEWABLES

REWRITE THE RULEBOOK

Mike Bartel
Vice-President,
Engineering Services

PLANNED MAINTENANCE SPENDING OF $200 MILLION TO:

- Improve productivity initiatives.
- Improve technical programs (parts refurbishment versus replacement).
- Develop strategic supplier relationships.
- Extend outage intervals (comprehensive parts analysis determines remaining life in parts).
- Enhance long-range planning.

Engineering Excellence as a Competitive Advantage

AS ONE OF THE FEW PURE POWER GENERATORS, TransAlta has learned how to operate plants safely, reliably and with a commercial mindset. In fact, employees are challenging conventional ways of maintaining power plants. What they're discovering is that the standards they are starting to follow are becoming the guidelines their own teams are setting.

"Who knows our operations better than us?" says Sid Nowicki, Outage Manager. "We know what it takes to keep our plants running well. We've got the engineering expertise and the operational experience to rewrite the rulebook."

Case in point: as part of regular maintenance, one unit at the 766 MW Keephills power plant was scheduled to have a chemical clean. This procedure removes built-up residue inside the boiler. According to the industry standard, this procedure should be done every six to eight years and takes about four days to perform. During this time, the plant is shut down. But the outage team did a detailed investigation of the 'plaque' on the boiler. It was far less than the industry standard predicted. Why?

"Over the years, our operations team has been diligent in making sure the boiler was 'brushed and flossed' regularly," says Mike Bartel, Vice-President, Engineering Services. "As a result, we concluded we could defer this procedure for another three years. This allowed us to save on immediate maintenance expense, avoid paying for replacement power and gain four days of revenue."

The combination of disciplined maintenance and engineering expertise allowed TransAlta to make a smart call. Diagnostic assessments, like the one that facilitated the deferral of the chemical clean, will continue at other TransAlta plants.

Increasingly, TransAlta employees are challenging old assumptions, asking tough questions and making decisions to safely and cost-effectively maintain our plants. We will continue to develop better standards. We will continue to evaluate the overall lifecycle of our plants when short- and long-term maintenance decisions are made. This comprehensive approach will pay off for shareholders in the short and long term.

(left) Sid Nowicki inside one of TransAlta's coal-fired plants in Alberta.

OUR APPROACH TO MAINTENANCE

Engineering
0 to plant life
- Condition assessment
- Technical plans
- Reliability programs
- Risk management strategies

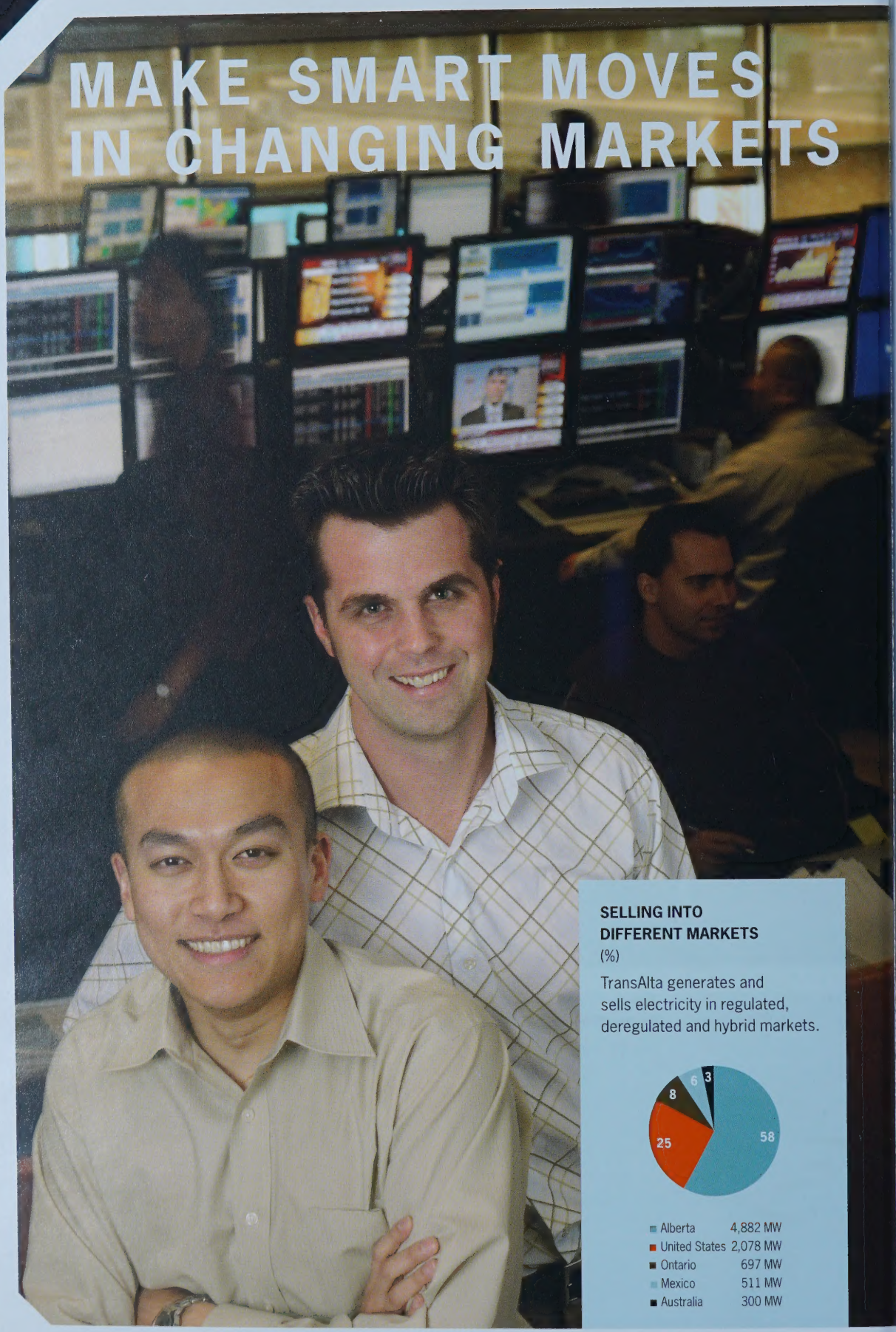
Long-range Planning
18 months to plant life
- Investment decisions
- Strategic partners
- Links to asset plans

Short-range Planning
4–18 months
- Leverage suppliers
- Productivity innovation
- Detailed plans
- Cost estimates

Turnaround Execution and Close-out
4 months to 30 days
- Reduce duration
- Real-time productivity
- Cost management

Turnaround Evaluation
30 days
- Lessons learned
- Updated equipment condition

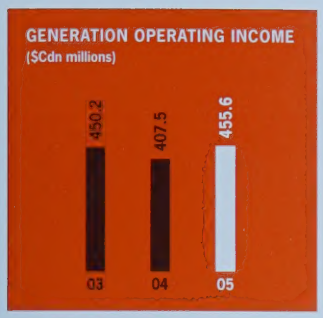
MAKE SMART MOVES IN CHANGING MARKETS

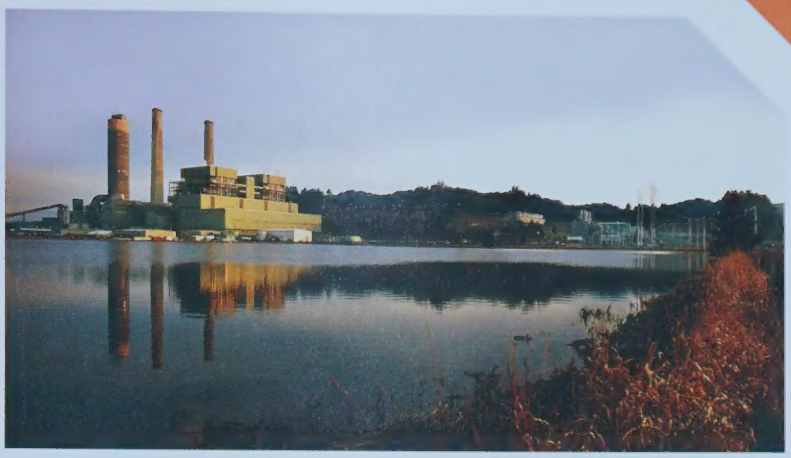


SELLING INTO DIFFERENT MARKETS
(%)

TransAlta generates and sells electricity in regulated, deregulated and hybrid markets.

Alberta	4,882 MW
United States	2,078 MW
Ontario	697 MW
Mexico	511 MW
Australia	300 MW





Centralia operations

Commercial Expertise as a Competitive Advantage

WHAT DO YOU GET WHEN YOU CROSS A WEATHERMAN WITH A FORTUNE TELLER who has a knack for numbers? Mark Kruzel is a trader in TransAlta's energy marketing business. His day starts at 5 a.m., when he gathers facts to determine how TransAlta can gain advantage in buying and selling power. These facts help him realize his goal: maximize TransAlta's gross margin. Some of the questions Mark might ask: Which way is that hurricane headed? How long will the heat wave last? What are natural gas prices doing today? The answers will give Mark a clearer picture of the supply and demand for both electricity and natural gas markets.

By 7 a.m., Mark talks with Kelvin Koay, Western U.S. Regional Portfolio Optimization Manager, to find out the availability of our plants. What power plants are down for scheduled maintenance in our markets? How many megawatts do we have available to sell from Centralia? How much power do we think customers and industry will need? Armed with Kelvin's asset recommendations, Mark and the trading team make smart, disciplined decisions to buy and sell power for the next five minutes to the next five years.

This controlled approach and thorough understanding of the market allowed TransAlta's asset teams to make some key decisions in 2005 that significantly added to the bottom-line. For example, in January 2005, our market analysts forecasted a dry spring in the Pacific Northwest resulting in lower hydro power production. This meant there would be a reduction in the supply of electricity and therefore higher prices. With that view in mind, our Centralia asset team, drawing on operations, maintenance and commercial expertise, decided to advance Centralia's planned major maintenance outage two weeks ahead of schedule. Moving a 30-day outage is not easy, especially considering the amount of manpower, parts and materials involved. But when the asset team compared the increased costs of moving the maintenance with the higher margin to be captured by selling Centralia's megawatts in an even better market, the decision was clear. The move paid off, contributing to Generation Operating Income in 2005.

Kelvin discusses market conditions with Brenda Marshall, a member of one of TransAlta's asset teams.

(left) Kelvin Koay and Mark Kruzel on TransAlta's trading floor.

GROW MEGAWATTS PROFITABLY AND CLEANLY

Innovation as a Competitive Advantage

IN MAY 2002, TRANSALTA JOINED EPCOR UTILITIES INC. (EPCOR) as co-owners of the 450 MW Genesee 3 (G3) power plant, the most technologically advanced coal-fired plant in Canada. Already under construction, the plant was expected to be up and running by 2005.

"We knew a power crunch was on the horizon and Albertans would need more electricity," says Gary MacPherson, Commercial Management Director. "We also knew Alberta has plenty of coal, so developing a coal-fired plant to meet this demand made sense." Still, coal-fired generation costs big bucks to build. Teaming up with EPCOR allowed TransAlta to share the market risk, accelerate the development of electricity generation in Alberta and grow the business.

G3 is just one example of how TransAlta is looking at innovative ways today to improve the bottom line tomorrow and increase shareholder value over the long term. When Western Australians faced power shortages, TransAlta's Parkeston Power Station was ready to pump spare megawatts into the grid. The problem? The regional transmission lines didn't have the capacity for Parkeston to export into the grid. Moving quickly, TransAlta and its partner, Newmont Mining, entered into a four-year deal that encouraged the government utility, Western Power, to build the required transmission line. By January 2005, the Parkeston facility was providing much-needed power, keeping customers' homes cool while TransAlta's capacity and revenues increased.

TransAlta continues to keep an eye on growing the company – looking for interesting opportunities and smart partnerships that leverage our operational and commercial expertise, minimize risk and support the balance sheet. We know the key to sustainable success is thinking outside the box, tackling new challenges when opportunities arise to create innovative solutions.

(right) TransAlta's Gary MacPherson and EPCOR's Al Pettican in front of G3.

OUR MARKETS

We see opportunity for growth in our existing markets, where we have the expertise in bidding, building and operating plants and selling the output. Our market diversity (represented by the following percentages) and varied fuel mix allow us to approach these opportunities in a prudent, disciplined manner.

ALBERTA – 58%

- Small, deregulated market – peak load of 9,500 MW
- Demand growing at 2.5% per year
- Long term, oil sands and clean coal technology provide growth opportunities

ONTARIO – 8%

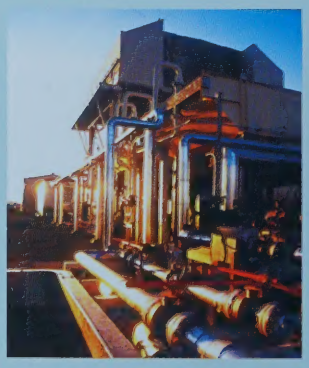
- Large, hybrid market – peak load of 26,000 MW
- Requires additional capacity
- Short-term opportunities in renewables

UNITED STATES – 25%

- Participate mostly in the Pacific Northwest
- Large, hybrid market – peak load of 28,000 MW
- Demand growing at 1.6% per year
- Opportunities for expansion of geothermal assets

MEXICO – 6%

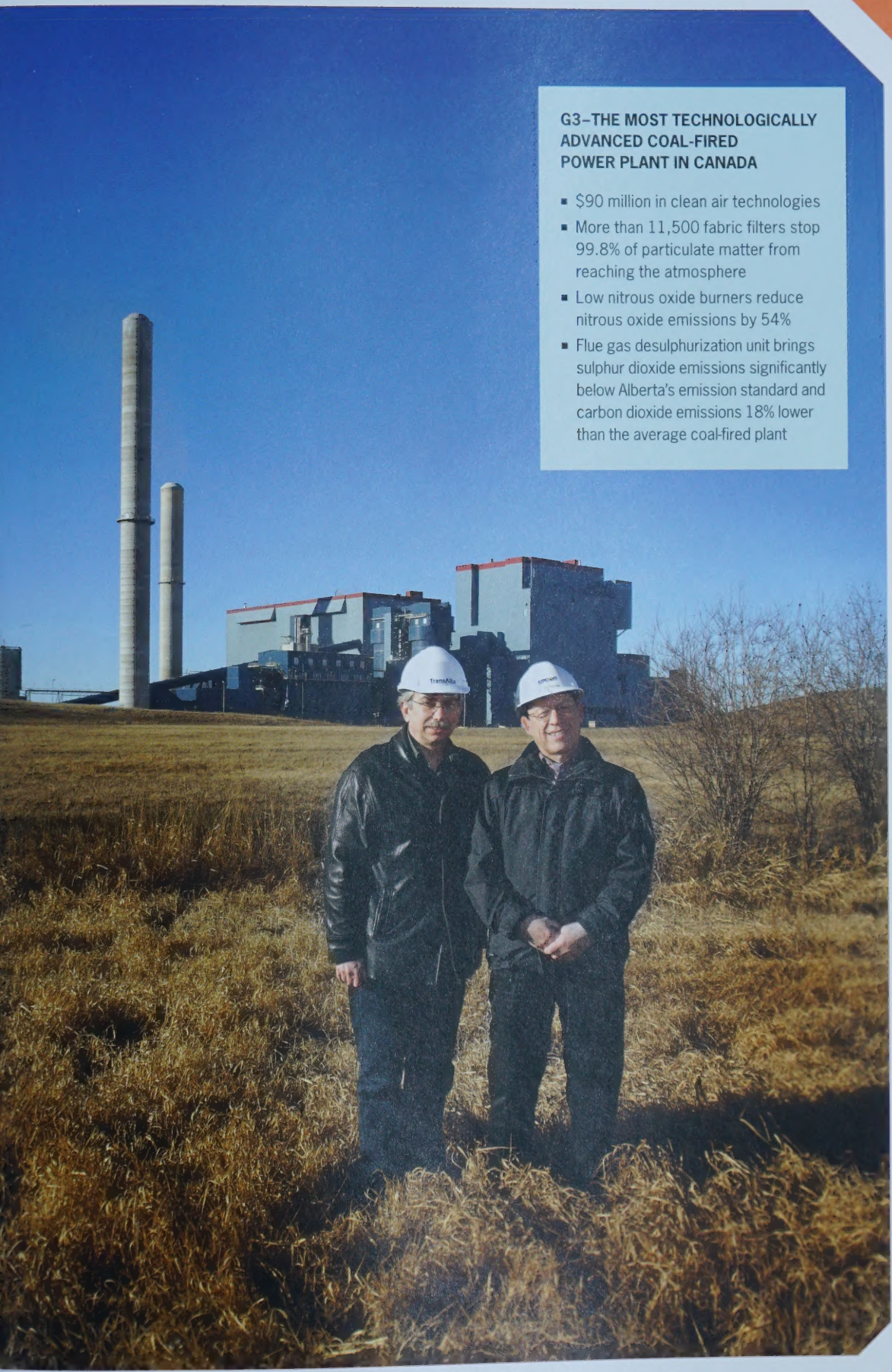
- Large, fully regulated market – peak load of 33,000 MW
- Strong demand growth near 5% per year
- Opportunities for acquisitions and new gas development



Parkeston power station in Australia

AUSTRALIA – 3%

- We limit ourselves to a niche market, doing cogeneration projects with resource companies in Western Australia.
- Our customers' power needs are growing as demand from Asia for natural resources increases dramatically.



G3–THE MOST TECHNOLOGICALLY ADVANCED COAL-FIRED POWER PLANT IN CANADA

- $90 million in clean air technologies
- More than 11,500 fabric filters stop 99.8% of particulate matter from reaching the atmosphere
- Low nitrous oxide burners reduce nitrous oxide emissions by 54%
- Flue gas desulphurization unit brings sulphur dioxide emissions significantly below Alberta's emission standard and carbon dioxide emissions 18% lower than the average coal-fired plant

Some of the many employees involved in sustainability efforts. From left to right: Sunny Sehgal, Becky Horvath, Shasta Kadonaga, Janet Leskiw and Greg Larson.

SUSTAINABILITY IS A BIG DEAL

06 Member of Dow Jones Sustainability Indexes DJSI

Sustainable Development as a Competitive Advantage

MORE THAN A DECADE AGO, TransAlta recognized that sustainable development would be a key element of business in the future. We were convinced then that operating in a manner that is economically rewarding and ethically, socially and environmentally responsible would be the way we'd conduct our business. We still believe this today.

Sustainable success at TransAlta is about thinking long term and ensuring that what we do meets the needs of today with a look to the future. Here are some of the ways our employees contribute to our sustainable development performance:

- Reduce and recycle waste.
- Implement safety processes.
- Manage stakeholder issues.
- Reclaim mined land and create wetlands.
- Control NO_X and SO_2 emissions.
- Improve plant production efficiency.
- Protect fish in lakes and rivers where we operate.
- Participate in the United Way.
- Volunteer in various non-profit organizations.
- Improve Aboriginal relations.

In 2005, our sustainable development performance was recognized by a number of external organizations including:

- **Corporate Knights** Global 100 Most Sustainable Corporations in the World, second consecutive year
- **Dow Jones Sustainability Index** World's Most Sustainable Companies, seventh consecutive year
- **FTSE4Good Global Index** London-based sustainability index, third consecutive year
- **Jantzi Social Index** Index of top 60 socially screened Canadian companies
- **KLD Global Climate 100 Index** Boston-based sustainability index
- **The Globe and Mail Newspaper** Top five best governed companies
- **PricewaterhouseCoopers** Trends 2006: Good Practices in Corporate Reporting, one of six Canadian companies listed
- **Clarkson Centre for Business Ethics and Board Effectiveness** Top five per cent for corporate governance
- **Canadian Institute of Chartered Accountants** Gold award for excellence in corporate reporting, sixth consecutive year

In 2005, TransAlta donated more than

$3.6 million

to community investment programs

GO THE EXTRA MILE

Active Employee Engagement in Community Partnerships

EILEEN STANLEY KNOWS A THING OR TWO about bringing a smile to people's faces. As a member of the TransAlta Community Transformers (TACT) donation committee in Fort McMurray, Alberta, she helps make decisions that make people happy. It just so happens that she's also "Blinkie the Clown", whose humorous antics create joy for young and old alike.

Through TACT, Eileen connects with her community, responding to local needs and priorities. TACT donations have helped organizations like the Fort McMurray Soup Kitchen and the Children's Centre. "Blinkie" sometimes makes the trip to these organizations' events. "I find that as a clown, I am able to reach out to people and even the smallest thing can make a big difference in someone's day," says Eileen.

Eileen is one of about 40 TransAlta employees in Fort McMurray, Centralia, Sarnia and Wabamun who decide where to donate more than $120,000 to strengthen their communities. Together with other TransAlta employees and the POWER (Projects Organized With Energetic Retirees) group, they volunteered a combined total of approximately 10,500 hours in 2005.

Whether it's participating in the United Way campaign, or reaching out to victims of the Asian Tsunami and Hurricane Katrina, employees and retirees are actively engaged in TransAlta's community investment program. They're also key to TransAlta community partnerships like the Calgary Stampede, Hull Child and Family Services, Southern Alberta Institute of Technology, the TransAlta Tri Leisure Centre, Fringe Theatre Adventures in Edmonton, Centralia College, Tri Community Festival of Trees, and Sarnia Celebration of Lights.

TransAlta's community investment focuses on a small number of initiatives where we can have the most meaningful impact over the long-term. In 2005, TransAlta invested over $3.6 million in communities where we live and work. That brings a lot of smiles.

(above) Eileen Stanley, a.k.a. 'Blinkie' sharing her time with youth in the community.

TransAlta is a power generation and wholesale marketing company focused on creating long-term shareholder value. We maintain a low-risk profile by operating a highly contracted portfolio of assets in Canada, the United States, Mexico and Australia. Our focus is to efficiently operate our coal-fired, gas-fired, hydro and renewable facilities in order to provide our customers with a reliable, low-cost source of power. For nearly 100 years, we've been a responsible operator and a proud contributor to the communities where we work and live.

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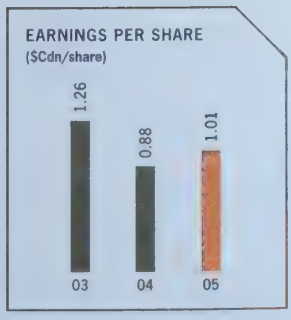
STEPHEN G. SNYDER
PRESIDENT & CHIEF EXECUTIVE OFFICER

In 2005, we did what we said we'd do. Our employees delivered tangible financial results. They performed with dedication, prudently allocating our resources, capturing market opportunities and finding ways to grow our megawatts safely, cleanly and profitably. Each of the previous stories offers an inside look at how TransAlta was able to succeed.



TURN THE PAGE FOR DETAILS ABOUT THE COMPANY'S 2005 PERFORMANCE AND WHERE WE'RE HEADED NEXT.

1 AVAILABILITY AND PRODUCTION

Many of our contractual agreements have availability and/or production of electricity as key factors in determining revenue. Running at 100 per cent availability means the plant is ready to run at full output every hour of every day throughout the year. However, plants need maintenance, and occasionally break down, so 100 per cent availability over an extended period of time is not achievable. Production is the amount of electricity we produce and is measured in gigawatt hours.

	03	04	05	Long-term target
Availability (%)	90.6	89.1	89.7	90+
Production (GWh)	53,134	54,560	54,561	Growth

2 CONTRACTS

Electricity prices can vary dramatically by the hour and year-over-year. To reduce our exposure to swings in market prices, we have chosen to contract a large percentage of our output through contracts with terms of one year or more. The weighted average remaining life of our current contracts is 12 years.

(%)	03	04	05	Long-term target
Contracted production	91	84	83	>75

3 MARGIN AND PRODUCTIVITY

We produce a commodity product in a long-term, capital-intensive business. Growing gross margin and increasing the productivity of our assets are essential for success. Fuel is a key cost driver, but it is largely recovered through contract terms and does not overly impact gross margin except for our merchant energy. Operations, maintenance and administration (OM&A) costs, together with production, drive our productivity, which is measured as dollars per megawatt hour. Productivity declined in 2005 from 2004 due to many factors. Productivity will be an area of focus for us in 2006.

($/MWh)	03	04	05	Long-term target
Margin	25.52	25.83	27.82	Increase
OM&A	10.53	10.50	11.31	Decrease

4 CAPITAL EXPENDITURES

We make capital expenditures to both grow and sustain the business, including maintaining our plants. Our growth is discretionary so expenditures will vary over time. Our goal with sustaining capital is to make it as predictable as possible.

($ in millions)	03	04	05	Long-term target
Growth	421	142	42	Variable
Sustaining	137	224	296	150–175

5 CASH FLOW*

Our cash requirements include maintaining our equipment, meeting debt repayment and non-controlling interest obligations and, of course, paying a dividend. Our goal is to exceed the cash requirements in every phase of our business and industry cycles in order to have cash available to invest in new growth, further reduce debt or return it to shareholders.

($ in millions)	03	04	05	Long-term target
Cash flow	527	613	640	550–650

** Cash flow as shown above is a non-GAAP measure as it includes the Mexico entities. Please refer to pg 73 for cash flow from operating activities calculated in accordance with GAAP.*

6 FINANCIAL RATIOS

Financial ratios measure our overall financial strength. There are three we focus on: cash flow to interest; cash flow to total debt; and debt to total capital.

Financial strength provides continued access to capital and greater flexibility in contracting the output of our plants.

The credit rating agencies also use the financial ratios when evaluating the company. In the long term, our financial condition will dictate our ability to grow. Building new generation plants or acquiring existing operations requires the capacity to take on new debt or to issue new equity. Our objective is to hold a strong investment grade credit rating.

	03	04	05	Target
Cash flow to interest (times)	3.3	4.1	4.6	4.2
Cash flow to total debt (%)	17.2	18.5	23.0	28
Debt to total capital (%)	47.7	47.4	43.3	45

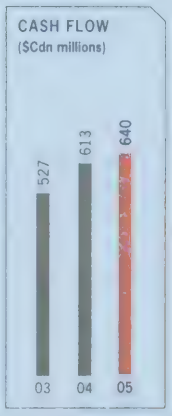
TARGET ACHIEVED

In 2005, our employees exhibited spirit, professionalism and real grit. They overcame a series of potential major setbacks – the shutdown of half of our Poplar Creek plant due to a fire at Suncor, the six-week closure of our Lake Wabamun plant due to the CN oil spill, and once-in-50-year flooding in Alberta affecting our hydro facilities. Every time, employees responded quickly and with dedication. Then they went out and found offsets. I am very proud of what they accomplished in the year.

You met some of these employees in the front of this book. They reflect the qualities that define our success: a clear focus on the fundamentals, a commitment to safety, operational discipline, and bottom-line results.

So how did we do?

In 2005 we delivered. We achieved $1.01 in reported earnings per share versus $0.88 in 2004, a 15 per cent increase. Our comparable earnings, reflecting the ongoing performance of our plants and trading operations, delivered $0.88 of earnings per share versus $0.66 in 2004, a 33 per cent increase.



Our cash flow is strong. It increased to $640 million, up from $613 million in 2004, $527 million in 2003 and $399 million in 2002. We have used this cash to maintain our plants, meet our debt obligations and pay dividends. In 2005, part of our remaining "free" cash was used to reduce $263 million in short- and long-term debt. We also spent $28 million to complete the investment of 225 megawatts (MW) of new capacity with the addition of Genesee 3 to our fleet, a joint venture with EPCOR.

For our shareholders, these efforts delivered a total shareholder return of 45 per cent for the year.

Our results were positively affected by improved market conditions in the Pacific Northwest and in Alberta. We benefited from reduced interest expense. A third factor in our improved results was our continuing progress in more effectively allocating our capital to maintain our plants.

These performance drivers are among six key factors that will determine our future success: contracting production; managing capital expenditures; achieving availability and production targets; driving higher margins and increased productivity; increasing our cash flow; and strengthening our balance sheet. (see "Progress Against Our Six Key Measures" on opposite page.)

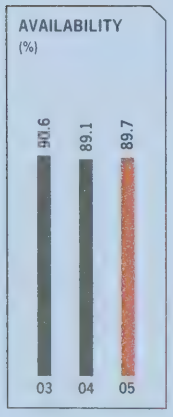
CONTRACTING PRODUCTION

I described two key events in last year's letter that would potentially be important contributors to our earnings – recontracting some of Centralia's output and contracting power from our Sarnia plant in Ontario.

During the year, our marketing team succeeded in signing contracts so that approximately 90 per cent of Centralia's output is contracted through 2006. And as of this writing, 85 per cent of its output is contracted for 2007.

We were also successful with Sarnia. In February of this year, we signed a five-year capacity contract for an average of 400 MWs with the Ontario Power Authority. Success on these two key issues will help drive our 2006 earnings improvement.

On a total plant portfolio basis, we will have approximately 83 per cent of our 8,468 MWs contracted for 2006 and 2007. That exceeds our target of having no less than 75 per cent of our total capacity contracted.



MANAGING CAPITAL EXPENDITURES

In last year's letter, I described our progress in changing the way we maintain our plants. In 2003, we began shifting from a reactive plan to a proactive multi-year plan for each of our generating plants.

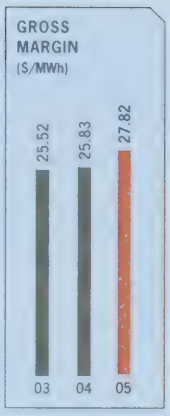
Our capital spending on major maintenance had been increasing. In 2003, we spent $35 million. In 2005, we spent $132 million. These increasing costs reflected the way we previously planned maintenance, the age of our plants and the growth in our fleet. Starting in 2006, and, as a direct result of the shift in plant maintenance, capital spending will decline to between $115 to $130 million. Further reductions will occur in 2007 and beyond. In simple terms, our new maintenance planning allows us to spend more efficiently and sustain plant performance.

ACHIEVING AVAILABILITY AND PRODUCTION TARGETS

Our plant availability in 2005 remained strong at 89.7 per cent, just shy of our 90 per cent target and slightly better than 2004. Production was also slightly higher at 54,561 gigawatt hours. That's a great feat when you consider the downtime our plants experienced due to external factors like the CN spill and the Suncor fire mentioned earlier. As well, the decommissioning of our Wabamun plant units one and two limited our production. Still, the higher production at our hydro facilities due to higher than normal rainfall and the addition of Genesee 3 helped offset the impact of these factors.

High availability is a key success factor for us. Our power purchase arrangements (PPAs) use availability as a key metric for payment. We can't inventory our product so we must also move quickly to sell our surplus power into spot markets. A defining factor for our continuing success is the ability of

our cross-functional asset teams to convert our market intelligence and strong plant performance into selling opportunities that strengthen our bottom line. You can see how this works on page 7.



REALIZING HIGHER GROSS MARGINS AND INCREASED PRODUCTIVITY

Because we produce a commodity product in a long-term, capital-intensive business, growing gross margins (revenue less fuel costs and purchased power) and increasing productivity of our assets are essential for our success. During 2005, our gross margins increased by eight per cent.

However, our productivity declined during the year as OM&A costs per megawatt hour (MWh) increased from $10.50 in 2004 to $11.31 in 2005 due to:

1. lower production due to plant outages beyond our control such as:
   a. the fire at Suncor's facility in Fort McMurray.
   b. the shutdown last summer at our Wabamun coal-fired plant due to the CN train derailment at Lake Wabamun.
2. higher costs due to:
   a. the addition of our new Genesee 3 coal-fired plant.
   b. higher fleet equipment repairs.
   c. a tough inflationary environment in Alberta.

Incentive compensation costs also went up reflecting both our improved share price and financial results.

While many of these factors are beyond our control, we can improve our performance. I have formed a senior level team to review every line item of our cost structure. We will look for areas to improve in 2006 and beyond.

STRENGTHENING OUR BALANCE SHEET

Our financial goal is to maintain the flexibility and stability necessary to thrive through all industry cycles. This starts with cash flow. In 2005, we continued to generate sufficient cash from operations to reinvest in our plants, meet our debt obligations and pay our dividend. After meeting our obligations, we still had cash remaining – what we call free cash flow.

In 2005 we used this free cash, over $250 million, to retire additional debt, which in turn decreased our interest costs. As I discussed last year, when we added new capacity in 1999 – 2004, our debt and interest costs went up. In fact, interest expense grew from $94 million in 1999 to $222 million in 2004. As these plants were commissioned and started to generate cash, we paid down debt. In 2005, our interest costs were reduced to $203 million, down $19 million from 2004. I expect a further reduction of $20 million in 2006.

In 2005, *Power Engineering* magazine recognized Genesee 3 (G3) as the world's best coal-fired power project. Construction of the facility was completed on time, on budget and with a lost-time injury rate 25 times better than the provincial average. G3 began commercial operation in March 2005 and is the largest unit to ever come online in Alberta.

This discipline further improved the financial ratios that determine our credit ratings. We made progress on our goal to meet the targets we believe necessary for a BBB+ rating. We achieved a cash flow to interest ratio of 4.6 times, cash flow to debt of 23 per cent and debt to capital of 43.3 per cent. These efforts are having results. In February 2006, Standard & Poor's upgraded our rating from BBB- to BBB. And Dominion Bond Rating Service recognized our efforts by removing the negative trend on our BBB rating late last year. These ratings are important to us as they allow us to cost-effectively support our contracting strategy and finance future growth.

We are also disciplined in managing our assets. Long-term investors remember that we have sold assets that no longer fit our portfolio requirements. This freed up underperforming capital. We've never lost sight of one of our key operating principles: "Cash is King."

SUSTAINABLE DEVELOPMENT

There is continued pressure on our industry to reduce our environmental footprint, specifically with respect to greenhouse gas (GHG), mercury, NO_X and SO_2 emissions. The Canadian government is still working through the Kyoto Protocol regulatory requirements, so it's difficult for us at this time to estimate the full impact it will have on our Canadian operations. Provisions in the PPAs for our Alberta coal-fired plants will allow us to recover compliance costs from the PPA customers.

Long-term investors will recall we invested $US200 million in our Centralia coal-fired plant to reduce SO_2 and NO_X. This plant is environmentally compliant in the United States under existing regulations. Still, we believe proactive, voluntary actions to lower costs and exposure to increasingly stringent environmental regulations are a prudent risk management strategy for our shareowners.

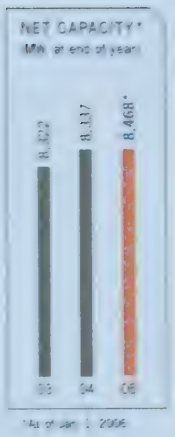
Our investment in renewable generation, through our geothermal and wind facilities, as well as our improvements in plant performance have reduced our emissions impact. Even though we've increased our generation by over 77 per cent, we've reduced our worldwide greenhouse gas intensity by 11 per cent from 1990 levels.

As well, we've continued to pursue an emissions offset strategy to mitigate future climate change costs. TransAlta was the first Canadian company to purchase international greenhouse gas credits in 2000.

building a portfolio of credits that has positioned TransAlta and its shareholders well as regulations intensify and the price of credits steadily rises.

As a founding member of the Canadian Clean Power Coalition, we've also been exploring the development of clean fuel technology. We'll substantially step up these efforts in 2006.

We're proud to be recognized for our environmental efforts, listed for the seventh consecutive year on the Dow Jones Sustainability Index and for the third consecutive year by FTSE4Good Global Index. TransAlta is also one of only five Canadian companies on the Corporate Knights list of the world's 100 most sustainable companies.



Outlook

After three to four years of turmoil in our industry, some positive indicators are emerging in the markets where we operate. We see reserve ratios (the amount of excess supply relative to peak demand) starting to decrease in some regions. As a result, prices are generally rising, although not dramatically. And new capacity will be needed over the next decade.

We do see challenges emerging. In addition to increasing fuel expense, we are faced with increased commodity prices. These are particularly noticeable in our coal production costs. We use a lot of diesel fuel in our truck fleet. This has doubled in price in 2004. A shortage of the huge tires used on our coal hauling trucks forced up tire prices. Limited availability of rail cars in the United States is affecting our ability to efficiently manage coal inventory. An unpredictably complicated process to obtain mining permits is slowing down our efforts to develop more cost-efficient coal reserves at the Centralia mine. I will address each of the challenges directly later in my comments.

We also see growth opportunities. We do not need to enter new markets or experiment with new technologies to find them.

New supply is needed in Alberta by 2009 and the expansion of the oil sands remains a big opportunity for generators. Ontario and the East Coast want wind development. In the United States, our geothermal assets have excellent, unexploited reserves and a strong market to sell into. All our customers in Australia are growing. Similarly, in Mexico, our customer, the Comisión Federal de Electricidad, is looking to contract more plants. I can assure you we will be very disciplined in our investment decisions. Our goals are simple: deliver our overall targets on equity, maintain a strong balance sheet and mitigate volatility as best we can to consistently grow our earnings and cash flow.

Four pillars of performance

Our response to these challenges and our strategic focus is based on what I call four pillars of performance. Collectively, these pillars create the sustainable competitive advantages we need to consistently grow our earnings.

I. OPERATIONAL EXCELLENCE

The first pillar is our day-to-day operations where we must effectively manage labour and fuel that represent 65 per cent of our operating costs. Key performance measures are in place or being established for all critical operations. Driving down our costs across our company remains a key priority for our management team. Richard Langhammer, Executive Vice-President, Generation Operations and his team are aggressively working on plans to achieve annual productivity savings equal to inflation.

For example, our Centralia coal operators extend the lives of our hauling truck tires by reducing the air pressure on the tires. The coal permitting team is making progress on obtaining new permits to mine richer coal seams that are closer to our plants. While we have sufficient alternate reserves to last until 2009, we will open the new seams whenever we get the permits and can exit from the older ones. We are building our capacity to handle more purchased coal in anticipation of better availability in the future.

Some of the Centralia issues may not be resolved until 2008 or 2009. In the meantime, our coal teams are doing everything they can to reduce costs in 2006 and 2007. Increasing power prices and improved margins at Centralia are helping offset these higher coal prices. I should note here that while fuel expenses at our Alberta coal-fired plants are passed through in our PPA contracts, our Alberta coal team is still very focused on containing costs.

II. PLANT MAINTENANCE

The second pillar involves on-going cyclical maintenance. Our goal is to drive down unplanned outages and drive up total availability while spending less capital and OM&A. We are achieving this goal by using our innovative predictive maintenance techniques, improving our equipment assessment capabilities and implementing our strategic supplier programs. By developing longer-term relationships with our key suppliers, we can more effectively take advantage of their capabilities to help us reduce costs. Continuous improvement is our focus now.

III. LIFECYCLE PLANNING

In 2006 – 2008, we will be shifting more of our efforts onto our last two pillars – lifecycle planning and portfolio management. Let's talk first about the former. We will invest a lot of money in cyclical maintenance over the life of our plants to keep them running at peak performance. Like a car, every plant is different in its characteristics, operating patterns and history. Over time, for every invested dollar, some plants tend to be more reliable than others. The better we are at predicting future costs and reliability

for our plants, the better we'll be able to plan for long-term capital spending and operating expenses. We want to spend just enough money, and no more, to extract value until we decide to close or sell a plant.

Linda Chambers, Executive Vice-President, Generation Technology & Supply Chain Management, and her team are developing the tools and the science we need to properly lifecycle plan for our plants. They are currently assessing our entire fleet and having their work verified by some top-notch experts in this field. By the end of 2006, we'll have our whole fleet analysis complete. That will allow us to make better fix/close/sell decisions. The savings over the next 20 years could be hundreds of millions of dollars in reduced capital spending.

working together for safety

Our people throughout the company continued to focus on our Target Zero initiative to improve safety performance. As an example, our injury frequency rate decreased from 1.69 in 2004 to 1.23 in 2005. That's one of the better records in our industry. Our near miss reporting program is also working. The number of near misses reported in 2005 was 16,500 versus only 3,000 in 2003.

IV. PORTFOLIO MANAGEMENT AND GROWTH

Just like investors who want to create a diversified investment portfolio to produce steady and predictable earnings, we have assembled a diversified portfolio of generating plants. The fuel and geographic diversity we enjoy reduces the risk of wide swings in our earnings. It has helped mitigate the impact of unpredictable events like the sharp increase in natural gas prices in 2005. It has allowed us to sustain our cash flow as we faced unresolved issues like the changing rules for merchant plants in Ontario. Our multi-year marketing strategy creates a portfolio of contracts that further supports our goals to reduce volatility and risk.

The cornerstone of all this work is commercial discipline – matching market analysis to plant costs. We rank our plants based on returns, comparing short-term opportunities to potentially longer-term challenges. We work hard to layer in our power contracts on the basis of output and the length of contracts so we can minimize the potential volatility in our cash flows. This is where we make our long-term risk mitigation strategies work.

Balancing fuel and geographic diversification with contracting length takes years of advance planning. By properly managing our fleet of assets, we'll be able to use our fleet to help take out the lumpiness inherent in our industry. Tom Rainwater, Executive Vice-President, Corporate Development & Marketing, and his team are on top of this opportunity adding their market knowledge to our lifecycle analysis to determine the best mix for our fleet.

It's already helped us plan for the 2009 – 2011 period. Now their sights are set on 2012 and beyond. This team is developing the models and skills that will allow us to wisely invest our capital in all our plants.

Your team

TransAlta's management team and Board remain focused and disciplined. Each quarter we check our progress against our short-term goals as well as our five-year plan. I report to you on them twice a year. We revisit our strategy constantly and adjust it to match changing environments. Our Board ensures all the proper linkages are in place. Our senior team's long-term compensation plan remains focused on share ownership (not stock options) and sustained performance. We benchmark our share performance against the TSX over a three-year period. And, we have mandatory stock ownership guidelines for the senior team.

Our Board continued to provide strong, on-going guidance. TransAlta is regularly recognized for its excellent corporate governance practices. The Board is involved in setting our strategies and risk profiles. They are actively engaged in learning our business and monitoring our progress, setting high standards, demanding results and offering support wherever needed. Their stewardship has ensured that TransAlta has not only survived the turbulence of the last few years but is well positioned to take advantage of improving better forward-looking markets.

Our management team, the Board and our employees will continue to be disciplined and deliver results for you, our shareowners in 2006.

STEPHEN G. SNYDER

President & Chief Executive Officer
March 3, 2006

Having served on the TransAlta Board for 16 years, I was honoured and delighted to be elected Chair in 2005. We have a very committed Board, we have great management, and I am happy to say the company had a good year.

Over the years on the TransAlta Board, I have seen many changes, both in the industry and in the company. The Board has kept a strong focus on oversight through a number of challenges, including deregulation, early growth, price volatility, and factors beyond TransAlta's control, always with our shareholders and other stakeholders in mind. We have also pursued many opportunities: development in new markets, commercial advancement of wind power, and entry into energy trading. Through all of this, we have maintained the dividend.

Your Board of Directors has a proven record of protecting shareholder interests. We are firmly committed to an ethical culture and good corporate governance. We constantly determine proper risk parameters, and engage management in setting and implementing appropriate strategies. This will continue to be our task as we go forward.

TransAlta is fortunate to have strong representation on its Board. Some have joined the Board in recent years, most recently Gord Lackenbauer, whom we welcomed to his first meeting in the third quarter of 2005. He brings a wealth of experience in banking and business, which will serve the Board well. Lou Hyndman, who has served the shareholders of the company for 20 years as a director, retires from the Board this year. He has been a valued colleague and his contribution was significant, driven by his vast experience in both politics and law.

Your Board consists of members from various regions of Canada and the world, which gives us a truly international perspective as TransAlta grows. We have broad experience in finance, risk management, operations, government relations, law and current governance practices. This knowledge, combined with management's considerable skill, helped put in place the structures and processes that provide the transparency investors expect. I am proud to say these efforts have been recognized: TransAlta was chosen by KPMG as one of Canada's top 10 most respected companies; The Globe and Mail's Report on Business ranked it among the best governed corporations in 2005; and it was given top honours by the Canadian Institute of Chartered Accountants for financial and corporate reporting for the sixth consecutive year.

Our Board recognizes the ever-growing emphasis on good governance and corporate responsibility. We have always believed in both, and they are a consistent theme in our dialogue with management.

A major focus of your Board is the building of a sustainable company – a company that will continue to drive toward profitable growth for you

over time. This is not a new theme. It began many years ago, continues today, and is our goal for the future. To have a sustainable company, we must anticipate issues, assess risks, encourage the development of management talent, and ultimately decide what best serves our shareholders and the communities we serve.

I well remember my initial reaction when the notion of sustainability, as it relates to environment issues, was introduced to the TransAlta Board in the early 90s. What will this mean? As directors of an energy company, we were intrigued by the notion of sustainability because we knew environmental issues would become increasingly important. We believed if TransAlta took proactive steps then, it would benefit not only our shareholders and other stakeholders, but the environment as well. This was something of a leap of faith, but we believed it was the right thing to do, and that conviction has proven correct many years later.

TransAlta's Board of Directors remains convinced that approaching business oversight from three perspectives – economic, environmental and social – creates competitive advantages. We recognize that our shareholders entrust this duty to us and we are determined to continue to earn that trust. After a strong year in 2005, we have turned our attention to 2006 and beyond, with your interests foremost in our minds.

Thank you for placing your confidence in us.

DONNA SOBLE KAUFMAN

Chair of the Board

CORPORATE GOVERNANCE

TransAlta's directors are experienced business leaders representing varied geographic and professional backgrounds, including business, finance, law and public service. On behalf of TransAlta's shareholders, the Board of Directors is responsible for the stewardship of the corporation, establishing overall policies and standards and reviewing strategic plans. During 2005, the directors met on 10 occasions, including one special meeting devoted exclusively to TransAlta's corporate strategy and direction.

After a detailed examination of the relationships between each of the directors and TransAlta, the Board determined that 10 of the existing 11 board members are independent excluding only Stephen Snyder, President and CEO of the company. All of the members of each of the committees of the Board are independent. The Board established three committees, which are briefly described as follows, to assist the Board in the performance of its obligations. Further detailed information with respect to TransAlta's approach to corporate governance is contained in the 2005 Management Proxy Circular.

AUDIT AND ENVIRONMENT COMMITTEE

The committee is responsible for reviewing financial reporting, financial controls, internal audit matters, financial risks inherent in the business and environmental risks and regulation affecting the corporation's activities. This committee met eight times in 2005. Committee chair: William D. Anderson. Members: Stanley J. Bright, Timothy W. Faithfull, Michael M. Kanovsky and Donna Soble Kaufman (as an ex-officio member).

TransAlta's Board of Directors at their annual strategy session in Ghost River, Alberta (July 2005).

Standing, left to right: Tim Faithfull, Luis Vázquez Senties, Louis Hyndman, Stanley Bright, Gordon Giffin
Sitting, left to right: Michael Kanovksy, William Anderson, Donna Soble Kaufman, Stephen Snyder, Kent Jespersen
Missing: Gordon Lackenbauer, who joined the Board in September 2005.

BOARD OF DIRECTORS

William D. Anderson Director since 2003 and resident of Montreal, Que. Mr. Anderson was President of BCE Ventures, a subsidiary of BCE Inc., from 2000 to 2005 and CFO of BCE Inc. from 1998 to 2000. He is a director of Bell Canada International Inc., the Four Seasons Hotels Inc. and Sears Canada Inc. He is a member of the Institute of Chartered Accountants of Ontario.

Stanley J. Bright Director since 1999 and resident of Vero Beach, Fla. Mr. Bright was Chair and CEO of MidAmerican Energy Company, a Des Moines, Iowa-based electric and gas utility company. He served as a director of MidAmerican Energy Holdings Company, a subsidiary of Berkshire Hathaway Inc., from 1999 to February 2006 and has been a director of MidAmerican Energy predecessor companies since 1987.

Timothy W. Faithfull Director since 2003 and resident of Oxford, United Kingdom. Mr. Faithfull was President and CEO of Shell Canada Limited from 1999 to 2003, when he completed a 36-year international oil and gas career with the Royal Dutch/Shell Group. He is a director of Canadian Pacific Railway Limited, the Canada-United Kingdom Colloquia, Shell Pension Trust Limited and AMEC plc in the United Kingdom.

HUMAN RESOURCES COMMITTEE

The committee is responsible for reviewing and recommending executive compensation programs, succession plans, and the CEO's compensation and performance, and acting as steward for the corporate pension plan. This committee met eight times in 2005. Committee chair: Stanley J. Bright. Members: Timothy W. Faithfull, C. Kent Jespersen, Luis Vázquez Senties and Donna Soble Kaufman (as an ex-officio member).

NOMINATING AND CORPORATE GOVERNANCE COMMITTEE

The committee is responsible for reviewing the composition and compensation of the Board of Directors and for developing the company's approach to governance issues. This committee met three times in 2005. Committee chair: Gordon D. Giffin. Members: C. Kent Jespersen, Michael M. Kanovsky, Gordon S. Lackenbauer, Louis D. Hyndman and Donna Soble Kaufman (as an ex-officio member).

2005 CHANGES

Jack Donald and John Ferguson retired from the Board in April 2005. Gordon Lackenbauer joined the Board in September 2005.

Gordon D. Giffin Director since 2002 and resident of Atlanta, Ga. Mr. Giffin is a Senior Partner of McKenna Long & Aldridge LLP. He is a director of Bowater, Inc., Canadian National Railway Company, Canadian Imperial Bank of Commerce and Canadian Natural Resources Ltd. He is a member of the Council of Foreign Relations, an advisory board member of the Canadian-American Business Council and serves on the Board of Trustees for the Carter Center in Georgia. Mr. Giffin served as United States Ambassador to Canada from 1997 to 2001.

Louis D. Hyndman, Q.C. Director since 1986 and resident of Edmonton, Alta. Mr. Hyndman is a Senior Partner of Field LLP. He is a director of Canadian Urban Ltd., EllisDon Inc., Enbridge Inc., Melcor Developments Ltd. and Meloche Monnex Inc.

C. Kent Jespersen Director since January 2004 and resident of Calgary, Alta. Mr. Jespersen worked with NOVA Corporation for over 20 years in various management positions, including president of NOVA International. He is Chair and CEO of La Jolla Resources International Ltd., Chair and a director of Geac Computer Corporation Limited and CCR Technologies Ltd. and a director of Matrikon Inc. and Axia NetMedia Corporation.

Michael M. Kanovsky Director since January 2004 and resident of Victoria, B.C. Mr. Kanovsky is President of Sky Energy Corporation. He has been involved in investment banking and the oil, gas and power industries for over 30 years. He is a director of Accrete Energy Corporation, Devon Energy Corporation, ARC Energy Trust, Bonavista Energy Trust and Pure Technologies Inc.

Donna Soble Kaufman Director since 1989 and resident of Toronto, Ont. Mrs. Kaufman is Chair of the Board of TransAlta Corporation. She was Chair and CEO of Selkirk Communications Ltd. from 1988 to 1989 and a partner of the law firm Stikeman Elliott from 1985 to 1997. Mrs. Kaufman is a director of BCE Inc., Bell Canada, Telesat Canada, Hudson's Bay Company, Historica, a Canadian historical society, and Baycrest, a centre for elderly and specialized care.

Gordon S. Lackenbauer Director since September 2005 and resident of Calgary, Alta. Mr. Lackenbauer was Deputy Chairman of BMO Nesbitt Burns Inc. from 1990 to 2004. He has been a director of Tembec Inc. since 1973 and Chair since 2005. Mr. Lackenbauer is also a Governor of Mount Royal College.

Stephen G. Snyder Director since 1996 and resident of Calgary, Alta. Mr. Snyder has been President and CEO of TransAlta Corporation since 1996. He is Chair of the Conference Board of Canada, the Calgary Zoological Society, the Calgary Stampede Foundation and a director of the Calgary Exhibition and Stampede and the Canadian Imperial Bank of Commerce.

Luis Vázquez Senties Director since 2001 and resident of Mexico City, Mexico. He is President and CEO and Chair of Group Diavaz, an oilfield services and natural gas distribution company he founded with partners in 1973. Mr. Vázquez is Chair of Compania Mexicana de Gas, S.A. de C.V. and of the Mexican Natural Gas Association.

FINANCIAL HIGHLIGHTS

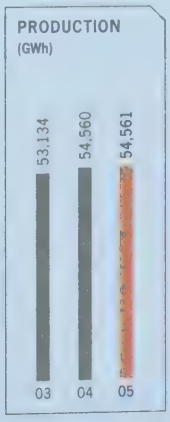
in millions of Canadian dollars, except per common share data

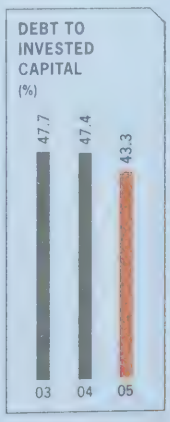
Year ended Dec. 31	2005	2004	2003
Revenues[1]	**$ 3,108.6**	$ 2,838.3	$ 2,520.9
Earnings from continuing operations[2]	**$ 186.8**	$ 160.6	$ 234.2
Net earnings	**$ 198.8**	$ 170.2	$ 234.2
Cash flow[1]	**$ 640.0**	$ 613.4	$ 526.9
Ratios			
Return on common shareholders' equity (%)	**7.3**	6.5	10.3
Debt to invested capital (%)	**43.3**	47.4	47.7
Cash flow to interest coverage (times)	**4.6**	4.1	3.3
Per common share data			
Earnings from continuing operations	**$ 0.95**	$ 0.83	$ 1.26
Net earnings	**$ 1.01**	$ 0.88	$ 1.26
Dividends	**$ 1.00**	$ 1.00	$ 1.00

1 *Revenues and cash flow shown are non-GAAP measures as they include the Mexico entities. Please refer to pages 31 to 115 for financial information prepared in accordance with GAAP.*

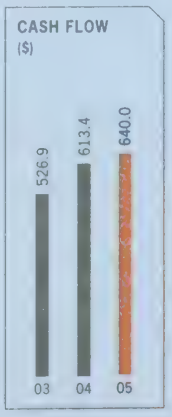
2 *Applicable to common shareholders.*

Net maximum capacity owned and operated





Includes non-recourse debt



OUR OUTLOOK AND FOCUS

GENERATION

Profile

- 8,468* MW of capacity
- 54,561 GWh produced at an average plant availability of 89.7%
- 49 facilities in four geographies: Canada; the United States; Mexico; and Australia
- Three surface coal mines: Highvale and Whitewood (Alberta, Canada); Centralia (Washington, United States.)
- Fuel mix of coal (58%), gas (29%), hydro (9%) and renewables (4%)
  - 18.6 million tonnes of coal mined
  - 100.4 million gigajoules (GJ) of gas consumed

* Not including plants in development

Industry Outlook

- Capacity oversupply in many regions is slowly being absorbed by annual load growth.
- Current conditions continue to favour low-cost producers with strong balance sheets.
- Spark spread profitability varies by regional power market fundamentals.
- Environmental pressures continue to drive industry focus towards gas, renewables and clean coal technology.
- Continued government oversight/intervention causes uncertainty in some markets where we operate.

Our Focus

- Set the highest safety standards.
- Continue to concentrate on achieving operational excellence while integrating new capacity.
- Reduce overall fuel costs/MWh.
- Drive top decile performance in major maintenance through lifecycle planning.
- Continue to diversify our fuel mix while capitalizing on opportunities that match our commercial and operational strengths.
- Grow our expertise in more environmentally sustainable generation through involvement in CE Gen, Vision Quest and the Canadian Clean Power Coalition.
- Grow our renewable capacity to 10% of our portfolio by 2010, with a short-term focus on wind.

ENERGY MARKETING

Profile

- 115,682 GWh of electricity and 413.8 million GJ of natural gas traded
- Trading focuses on enhancing returns of generation assets through disciplined approach to asset optimization and capitalizing on short-term market opportunities.
- Trading involves matching buyers and sellers, arranging for transmission capacity and scheduling movement of the commodity.
- Development and marketing focuses on selling long-term contracts, designing new products for customers and identifying strategic growth opportunities.

Industry Outlook

- The real-time nature of the commodity continues to call for active management of buying, selling and moving power and natural gas.
- Liquidity varies regionally and remained low in medium- and long-term markets in 2005, but short-term and real-time markets will continue to be active.
- Financially backed players are entering the business, enhancing liquidity in the forward power markets.

Our Focus

- Maximize margins on non-contracted generation production.
- Reduce cost of replacement power for plant outages.
- Reduce our exposure to any one market by continuing to focus our growth in our key geographies.
- Provide critical market knowledge to help identify growth opportunities and support corporate investment decisions.

FINANCIAL

Profile

- Debt ratings: BBB (DBRS); BBB (S&P); Baa2 (Moody's)
- 43.3% debt to invested capital
- $1 per share dividend
- Interest coverage at 4.6 times
- Cash flow to debt ratio: 23%

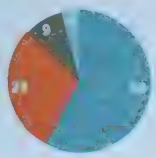
Industry Outlook

- Prudent fiscal management continues to be critical in medium term and long term.
- Consolidation of key players in the United States.
- Continued focus on balance sheet strength.

Our Focus

- Maximize cash flow from operating activities.
- Achieve BBB+ credit metrics by 2007.

CAPACITY BY FUEL TYPE
(%)



- Coal
- Gas
- Hydro
- Renewables

CAPACITY BY GEOGRAPHY
(%)

- Canada
- United States
- Mexico
- Australia

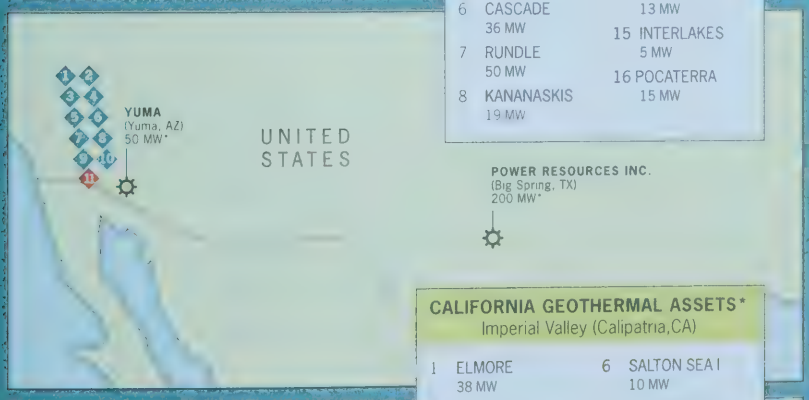
NO. OF EMPLOYEES BY REGION
(Total 2,657)

- Canada
- United States
- Mexico
- Australia

INTERNATIONAL OPERATIONS

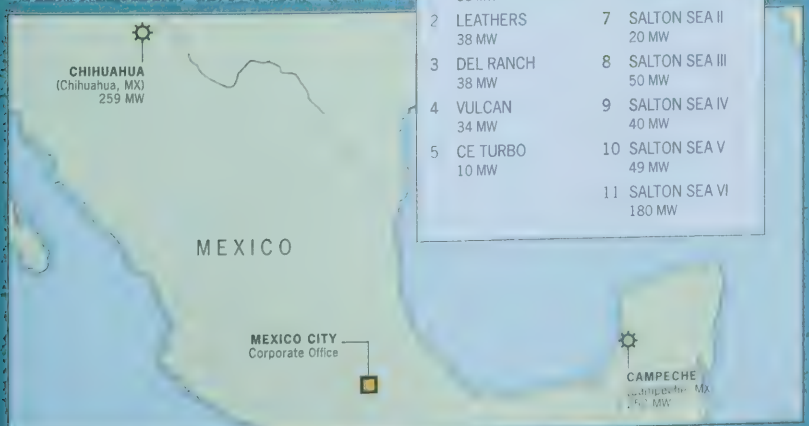
ALBERTA PPA ASSETS

1	SUNDANCE 2,020 MW	9	HORSESHOE 14 MW
2	KEEPHILLS 766 MW	10	GHOST 51 MW
3	SHEERNESS 770 MW 25% owned	11	BEARSPAW 17 MW
4	BRAZEAU 355 MW	12	SPRAY 103 MW
5	BIGHORN 120 MW	13	THREE SISTERS 3 MW
6	CASCADE 36 MW	14	BARRIER 13 MW
7	RUNDLE 50 MW	15	INTERLAKES 5 MW
8	KANANASKIS 19 MW	16	POCATERRA 15 MW



CALIFORNIA GEOTHERMAL ASSETS*
Imperial Valley (Calipatria,CA)

1	ELMORE 38 MW	6	SALTON SEA I 10 MW
2	LEATHERS 38 MW	7	SALTON SEA II 20 MW
3	DEL RANCH 38 MW	8	SALTON SEA III 50 MW
4	VULCAN 34 MW	9	SALTON SEA IV 40 MW
5	CE TURBO 10 MW	10	SALTON SEA V 49 MW
		11	SALTON SEA VI 180 MW



GENERATION FACILITIES	OWNED
Coal-fired plants	4,887 MW
Coal-fired plant (IN DEVELOPMENT)	450 MW
Hydro plants	802 MW
Gas-fired plants	2,464 MW
Wind-powered plants	152 MW
Geothermal plants	163 MW
Geothermal plant (IN DEVELOPMENT)	90 MW
Corporate offices	
Energy Marketing offices	

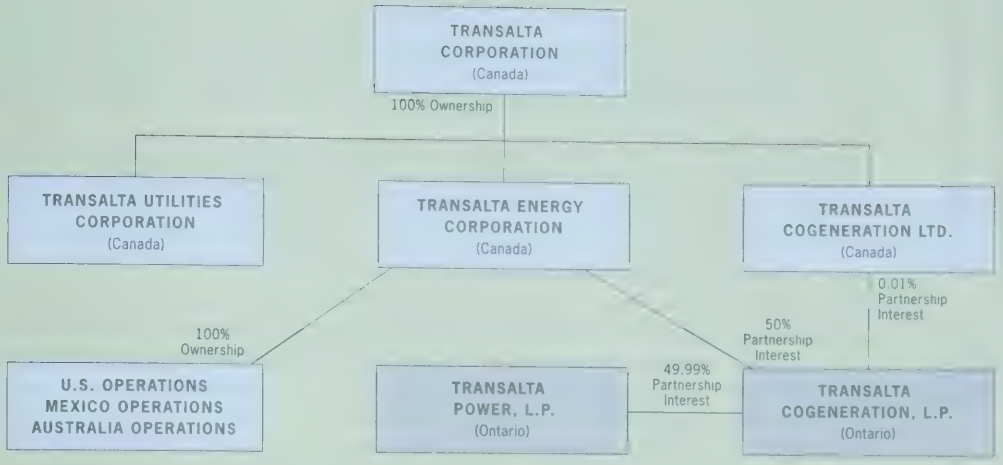
** 50 per cent ownership of MW indicated*

PLANT SUMMARY

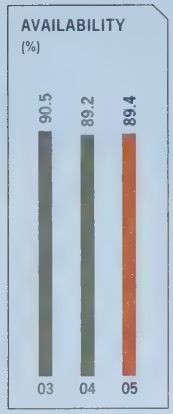
Facility	Capacity (MW)	Ownership (%)	TransAlta operated	Capacity owned or operated (MW)	Fuel	Revenue source*	Contract expiry date
Genesee 3	450	50	No	225	Coal	Merchant	–
Keephills	766	100	Yes	766	Coal	Alberta PPA	2020
Keephills 3 [1,2]	450	100	Yes	450	Coal	Merchant	–
Sheerness	770	25	No	193	Coal	Alberta PPA	2020
Sundance	2,020	100	Yes	2,020	Coal	Alberta PPA	2017, 2020
Wabamun	279	100	Yes	279	Coal	Merchant	–
Fort Saskatchewan	118	30	Yes	35	Gas	Long-term contract (LTC)	2019
Meridian	220	25	Yes	55	Gas	LTC	2024
Poplar Creek	356	100	Yes	356	Gas	LTC & Merchant	2024
Hydro assets [3]	801	100	Yes	801	Hydro	Alberta PPA	2013–2020
Castle River [4]	46	100	Yes	46	Wind	LTC	2011
McBride Lake	75	50	Yes	38	Wind	LTC	2022
Summerview	68	100	Yes	68	Wind	Merchant	–
ALBERTA TOTAL	**6,419**			**5,332**			
Mississauga	108	50	Yes	54	Gas	LTC	2017
Ottawa	68	50	Yes	34	Gas	LTC	2012
Sarnia	575	100	Yes	575	Gas	LTC & Merchant	2022
Windsor-Essex	68	50	Yes	34	Gas	LTC & Merchant	2016
ONTARIO TOTAL	**819**			**697**			
Centralia	1,404	100	Yes	1,404	Coal	Merchant	–
Binghamton	47	100	Yes	47	Gas	Merchant	–
Centralia Gas [5]	248	100	Yes	248	Gas	Merchant	–
Power Resources	200	50	No	100	Gas	Merchant	–
Saranac	240	37.5	No	90	Gas	LTC	2009
Yuma	50	50	No	25	Gas	LTC	2024
Imperial Valley [6] geothermal assets	327	50	No	163	Geothermal	LTC & Merchant	2016–2035
Salton Sea VI [1]	180	50	No	90	Geothermal	Merchant	–
Skookumchuck	1	100	Yes	1	Hydro	Merchant	–
UNITED STATES TOTAL	**2,697**			**2,168**			
Campeche	252	100	Yes	252	Gas	LTC	2028
Chihuahua	259	100	Yes	259	Gas	LTC	2028
MEXICO TOTAL	**511**			**511**			
Parkeston	110	50	Yes	55	Gas	LTC	2016
Southern Cross	245	100	Yes	245	Gas & Diesel	LTC	2016
AUSTRALIA TOTAL	**355**			**300**			
TOTAL	**10,801**			**9,008**			

1 *These facilities are currently under development*
2 *Formerly referred to as Centennial*
3 *Comprised of 13 facilities*
4 *Includes eight individual turbines at other locations, one of which moved from testing to production*
5 *Formerly referred to as Big Hanaford*
6 *Comprised of 10 facilities*
* *Merchant includes both contracted and spot sales*

Details as of Jan.1 2006



This management's discussion and analysis (MD&A) should be read in conjunction with the consolidated financial statements included in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). The effect of significant differences between Canadian and U.S. GAAP has been disclosed in *Note 25* to the consolidated financial statements. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Feb. 16, 2006. Additional information respecting TransAlta Corporation (TransAlta or the corporation), including its annual information form, is available on SEDAR at www.sedar.com.

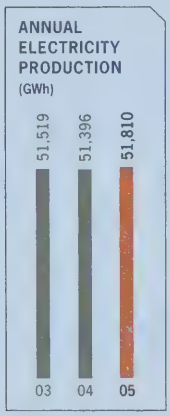


RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segment. TransAlta has two business segments: Generation and Energy Marketing. TransAlta's segments are supported by a corporate group that provides finance, treasury, legal, information technology, human resources and other administrative support. The costs of the corporate group are allocated to the business segments unless these costs are directly attributable to discontinued operations.

Some of TransAlta's accounting policies require management to make estimates or assumptions that in some cases may relate to matters that are inherently uncertain. Critical accounting policies and estimates include: revenue recognition; valuation and useful life of property, plant and equipment (PP&E); asset retirement obligations; valuation of goodwill; income taxes; and employee future benefits. See additional discussion under Critical Accounting Policies and Estimates in this MD&A.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency transactions and balances is discussed with the relevant income statement and balance sheet items. While individual balance sheet line items will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items is reflected in the cumulative translation account on the consolidated balance sheet.



HIGHLIGHTS AND SUMMARY OF RESULTS

During 2005, the corporation:

- Generated net earnings of $198.8 million compared to $170.2 million for 2004 and $234.2 million for 2003.
- Generated earnings on a comparable basis of $173.8 million compared to $128.1 million for 2004 and $128.7 million for 2003. Earnings on a comparable basis is not defined under GAAP. Refer to the Non-GAAP Measures section on page 66 of this MD&A for a further discussion of earnings on a comparable basis, including a reconciliation to net earnings.
- Generated cash flow from operations of $619.4 million compared to $591.2 million in 2004 and $474.3 million in 2003.
- Invested $325.5 million in new and existing plants versus $345.7 million in 2004 and $434.4 million in 2003.
- Made net repayments of short- and long-term debt of $262.9 million compared to $367.4 million in 2004 and $226.7 million in 2003.
- Settled several outstanding tax positions resulting in $25.0 million in income tax recoveries.
- Signed a four-year agreement to deliver 375 megawatts (MW) of electricity per year from our Centralia coal-fired plant. This contract replaces a number of prior contracts that have expired in recent periods. The pricing terms of this new contract are considerably higher than those that have expired.
- Had its credit rating trend upgraded by Dominion Bond Rating Service (DBRS) from "BBB Negative" trend to "BBB Stable" trend and its Standard & Poor's (S&P) credit rating upgraded from "BBB- Stable" to "BBB Stable".

The following table depicts key financial results and statistical operating data:

Year ended Dec. 31	2005	2004	2003
		(Restated, Note 1)	(Restated, Note 1)
Availability (%)	**89.4**	89.2	90.5
Production (GWh)	**51,810**	51,396	51,519
Electricity trading volumes (GWh)	**115,682**	84,404	89,833
Gas trading volumes (million GJ)	**413.8**	430.4	270.2
Revenue	**$ 2,838.5**	$ 2,586.2	$ 2,413.5
Gross margin	**$ 1,462.6**	$ 1,356.8	$ 1,325.3
Operating income [1]	**$ 441.2**	$ 470.9	$ 558.7
Earnings from continuing operations [2]	**$ 186.8**	$ 160.6	$ 234.2
Earnings from discontinued operations, net of tax [3]	**12.0**	9.6	–
Net earnings applicable to common shareholders	**$ 198.8**	$ 170.2	$ 234.2
Basic earnings per common share:			
Earnings from continuing operations	**$ 0.95**	$ 0.83	$ 1.26
Earnings from discontinued operations	**0.06**	0.05	–
Net earnings	**$ 1.01**	$ 0.88	$ 1.26
Diluted earnings per common share:			
Earnings from continuing operations	**$ 0.95**	$ 0.83	$ 1.26
Earnings from discontinued operations	**0.06**	0.05	–
Net earnings	**$ 1.01**	$ 0.88	$ 1.26
Cash flow from operating activities	**$ 619.4**	$ 591.2	$ 474.3

1 *Operating income is not defined under GAAP. Refer to the Non-GAAP Measures section of this MD&A for a further discussion of operating income, including a reconciliation to net earnings.*

2 *Continuing operations include the Generation and Energy Marketing segments plus corporate costs not directly attributable to discontinued operations.*

3 *Discontinued operations consist of the Transmission operation which was sold on April 29, 2002 and the Alberta Distribution and Retail operations which was sold on Aug. 31, 2000.*

STRATEGY AND KEY MEASURES

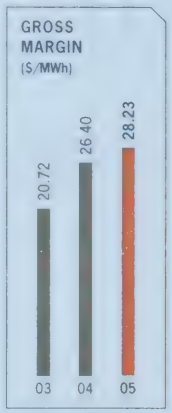
Our business is to invest in long-term electricity assets and consistently create value. Our goal is to deliver 10 per cent average total shareholder returns over time. We have six key measures with long-term targets that are critical to meeting our goal. These key measures include a mix of operational, risk management and financial metrics against which we can measure our performance.

1. Availability and Production

Our plants must be available to meet the requirements of customers who have contracted our capacity or to sell production into merchant markets to capture opportunities. Our long-term target is to have our plants available 90 per cent or more of the time.

Availability can be limited by the requirement to perform planned maintenance at regular intervals or by outages and de-rates caused by minor mechanical problems. While we expect there will be a certain number of these unplanned outages, our goal is to minimize these events through constant equipment monitoring and assessment, rolling maintenance plans and the formation of strategic relationships with suppliers. Over the past three years, we have achieved an average availability of 89.7 per cent, which is in line with our long-term target of 90 per cent availability.

Production is affected by our total generating capacity, the availability of our equipment and market conditions. During 2005, production increased as Genesee 3 was commissioned and we received a full year of production from the Summerview wind farm. The increase was partially offset by the decommissioning of units one and two of the Wabamun plant in December 2004. Production was negatively impacted by shutdowns caused by the Canadian National Railway (CN) train derailment at Lake Wabamun and a fire at a Suncor plant in Fort McMurray that impacted the production from our Poplar Creek plant. Production decreased in 2004 as incremental production from the Sarnia plant, which was commissioned during 2003, was more than offset by lower production from our Centralia coal-fired plant.



2. Contracts

Our strategy is to contract a minimum of 75 per cent of our available output in any year to minimize our exposure to electricity and gas price swings in the markets in which we operate. This strategy allows us to achieve a balance between cash flow stability and the ability to capture short-term opportunities in the markets.

Contracts can be structured as capacity commitments (Alberta Power Purchase Arrangements (PPA), and contracts for our Australia and Mexico plants), which allow TransAlta to minimize fuel cost risks by passing the majority of these costs on to the customer. We also have contracts that combine production, availability and other services, where we are compensated for availability, electricity and steam production (Ontario and Alberta gas plants) and long-term bilateral contracts directly with our customers (Centralia coal-fired plant). The remainder of our production is sold into markets as spot sales or under contracts with terms less than one year.

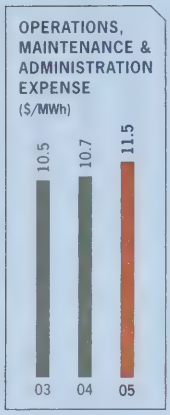
During 2005, approximately 82 per cent of the Generation segment's revenues were derived from contracts with terms greater than one year. This percentage is lower than prior years as we have increased our merchant generating capacity with the addition of the Genesee 3 plant. On Feb. 15, 2006, we signed a five-year contract with the Ontario Power Authority to be available to supply an average of 400 MW of electricity to the Ontario market. This contract is effective Jan. 1, 2006.

A further discussion of these contracting strategies is provided, beginning on page 41 of this MD&A.

3. Margin and Productivity

Together with our increasing production base, growing our gross margin is essential for our success. We manage margins through our contracting strategy and fuel cost management. In our key markets in Alberta and the Pacific Northwest, electricity prices have been driven by fluctuating gas costs and the availability of water for hydro production, particularly in the Pacific Northwest.

Gross margins at our contracted gas plants are generally managed by passing fuel costs on to customers or by signing long-term gas contracts that match the terms of the electricity and thermal sales. At our Centralia operations, our mine and major maintenance strategy is to minimize fuel costs and maximize availability in order to capture margin. At our merchant gas plants, the margins are driven by the ratio of gas prices to electricity prices in that market (market heat rates) and our ability to produce electricity at heat rates that are better than the market heat rates.



During 2005, our margins increased due to higher gas prices in the North American markets, which in turn influenced electricity prices. These higher electricity prices had a significant impact on the margins from our coal-fired plants. In addition, merchant capacity from the newly commissioned Genesee 3 plant and increased hydro production also contributed to higher margins. These increases were partially offset by higher fuel costs at the coal-fired plants.

In 2004, gross margin increased due to higher merchant capacity and lower planned maintenance outages. Similar to 2005, revenues were offset by higher fuel costs. 2003 also included a loss from trading in Transmission Congestion Contracts (TCCs).

In 2005, gross margin per megawatt hour (MWh) increased over 2004 due to higher hydro production and higher merchant capacity from the coal-fired plants that benefited from higher electricity prices. These gains were partly offset by higher coal costs. Margins in 2004 were similar to 2003 as higher prices from coal plants were offset by increased fuel costs. In addition, the 2003 margins included a loss from TCCs in our Energy Marketing Segment.

We will continue to focus on increasing our margins by increasing plant availability to capture market opportunities, matching revenues and fuel cost contracts at our gas plants and developing long-term fuel plans for our coal-fired plants.

During 2005, our operations, maintenance and administration (OM&A) costs increased from $547.5 million to $596.0 million due to the addition of Genesee 3 and higher salary, contracting and material costs due to market demand for labour and commodities. Labour costs also increased from the impact of our increasing share price on stock-based compensation.

In 2004, OM&A costs increased over 2003 as a result of the Sarnia plant commissioned in March 2003.

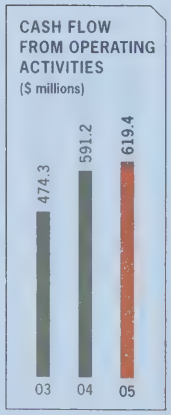
4. Capital Expenditures

We are in a long-cycle capital intensive business. Since our growth in 2000-2003, our capital expenditures have declined significantly. Despite an increase in capital spending on planned maintenance activities in 2005, capital expenditures have declined as a result of lower capital spending on growth initiatives.

5. Cash Flow

Our goal is to generate $550-$650 million of cash flow from operating activities to meet the requirements of maintaining our equipment, reducing our debt, maintaining our dividend and having cash available to invest in growth initiatives.

In 2005, cash flow from operating activities improved to $619.4 million compared to $591.2 million in 2004. Improved net earnings, coupled with higher depreciation expense, contributed to the increase. In 2004, cash flow from operating activities improved $116.9 million compared to 2003, due primarily to improved non-cash operating working capital balances and increased earnings.



6. Financial Ratios

TransAlta is focused on maintaining a strong balance sheet and investment-grade credit rating. Financial strength provides us with continued access to capital and greater flexibility in contracting the output of our plants.

In the long term, our financial condition will dictate our ability to grow. Our objective is to maintain an investment-grade rating to give us the capacity to take on new debt or issue equity.

At Dec. 31, 2005, our total debt (including non-recourse debt) to invested capital was 43.6 per cent (39.8 per cent excluding non-recourse debt) compared to Dec. 31, 2004 of 46.4 per cent and Dec. 31, 2003 of 46.2 per cent. Cash flow to interest increased to 4.8x compared to 4.3x in 2004 and 3.4x in 2003. Cash flow to total debt increased to 23.5 per cent from 19.1 per cent in 2004 and 17.1 per cent in 2003.

COMPARABLE EARNINGS

In 2005, comparable earnings increased to $173.8 million compared to $128.1 million in 2004 and $128.7 million in 2003 as shown below:

Comparable earnings for the year ended Dec. 31, 2003	$ 128.7
Decreased Generation gross margins	(19.6)
Decreased lost margins due to planned maintenance	15.6
Increased Energy Marketing gross margins	35.5
Increase in operational and administrative costs	(6.7)
Increased depreciation	(27.7)
Increase in earnings attributable to non-controlling interest	(11.8)
Lower interest expense	4.7
Lower income taxes	8.4
Other	1.0
Comparable earnings for the year ended Dec. 31, 2004	$ 128.1
Increased Generation gross margins	107.1
Increased lost margins due to planned maintenance	(11.4)
Increased Energy Marketing gross margins	10.1
Increase in operational and administrative costs	(48.5)
Increased depreciation	(10.4)
Increase in earnings attributable to non-controlling interest, net of impairment	(8.7)
Lower interest expense	18.8
Higher income taxes	(11.3)
Comparable earnings for the year ended Dec. 31, 2005	**$ 173.8**

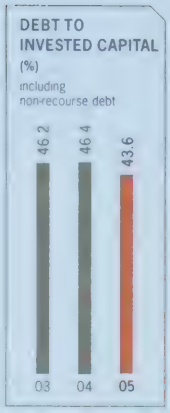
For the year ended Dec. 31, 2005, our gross margins were $105.8 million higher than in 2004 due to the addition of Genesee 3, higher hydro production, higher electricity prices captured by our Centralia and Alberta coal-fired facilities, higher contract prices at some of our gas plants and higher trading margins from our Energy Marketing segment. These increases were partially offset by increased coal costs in both our Alberta and Centralia coal-fired plants, increased net penalties at our Alberta coal-fired plants as a result of our major maintenance activities and the decommissioning of units one and two of the Wabamun plant. In 2004, our gross margins increased $31.5 million compared to 2003. In 2003, the results of our Energy Marketing segment were negatively impacted by losses on TCCs in the amount of $33.3 million.

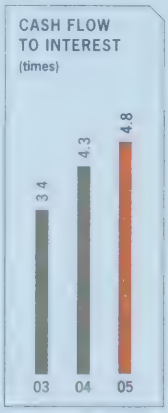
OM&A costs increased $48.5 million due to the addition of Genesee 3, equipment repairs, escalations of material costs, increased incentive compensation costs and increased labour costs. These increases were partially offset by lower planned maintenance expenses. Our OM&A costs in 2004 were $6.7 million higher than in 2003 due to the addition of our Sarnia plant, partially offset by reduced planned maintenance expenses.

Depreciation and amortization increased by $10.4 million due primarily to the addition of Genesee 3. In 2004, depreciation and amortization increased $27.7 million compared to 2003 due to the addition of the Sarnia plant, increased depreciation at the Ottawa, Windsor and Mississauga plants and depreciation of increased capital spending on major maintenance.

Interest expense declined in 2005 by $18.8 million compared to 2004 as we redeemed $300.0 million in preferred securities early in 2005. Interest expense declined from 2003 to 2004 by $4.7 million due to overall debt reductions.

Non-controlling interests decreased to $18.5 million in 2005. Included in this amount is $36.2 million related to the impairment of the Ottawa facility discussed later in Significant Events. Excluding this amount, non-controlling interests increased in 2005 as we disposed of our remaining interest in TransAlta Power, L.P. (TA Power) in 2004. In 2004, non-controlling interests increased $11.8 million due to the disposition of our Sheerness Generating Station to TransAlta Cogeneration, L.P. (TA Cogen) in July 2003.





EARNINGS PER SHARE AND CASH FLOW

Earnings from continuing operations for 2005 were $186.8 million ($0.95 per common share), compared to $160.6 million ($0.83 per common share) for 2004 and $234.2 million ($1.26 per common share) in 2003. The increase in 2005 was driven by increased spark spreads (the margin between the price of electricity and the price of natural gas consumed to produce power) and pricing in all markets, the commissioning of Genesee 3 and higher hydro reservoir levels, offset by higher coal costs. The variance from 2004 to 2003 was due primarily to the $145.8 million after-tax gain on the sale of the Sheerness Generating Station and the $59.0 million after-tax turbine impairment charge in 2003. See Significant Events below for further discussion.

SIGNIFICANT EVENTS

Our consolidated financial results include the following significant events. All gains and losses discussed below are presented as pre-tax (after-tax) amounts, unless otherwise noted.

2005

Commissioning of Genesee 3

On March 1, 2005, we, jointly with EPCOR Utilities Inc. (EPCOR), commissioned the third unit of the Genesee coal-fired facility. We own a 50 per cent interest in this third unit.

Wabamun Outage

On Aug. 3, 2005, a CN train derailment resulted in an oil spill at Lake Wabamun, Alberta. We were forced to shut down unit four of our Wabamun coal-fired plant as a result. The facility was restored to full operations on Sept. 11, 2005. We estimate that we lost between $15 million and $18 million in operating income as a result of this incident.

Impairment of the Ottawa Facility

In the fourth quarter of 2005, after completing our impairment reviews, we concluded that the carrying value of the Ottawa cogeneration facility exceeded its fair value in the accounts of TA Cogen. Consequently, TA Cogen recorded an impairment provision of $78.3 million in the fourth quarter of 2005. In the accounts of the corporation, however, the carrying value of the Ottawa facility is lower than that of TA Cogen. TA Cogen purchased this facility from the corporation at a price that was higher than the cost the corporation paid to construct it. We have recognized a $36.2 million charge in the accounts to reflect the difference in carrying values between the accounts of the corporation and those of TA Cogen. This charge is offset by a reduction in the earnings attributable to the non-controlling interests in our consolidated statement of earnings. The net result is that the impairment of the plant in the accounts of TA Cogen has had no impact on the net earnings of TransAlta Corporation.

2004

Decommissioning of Wabamun Plant

In the fourth quarter of 2002, we implemented a phased decommissioning of the Wabamun facility by removing the 139 MW unit three from service in 2002 and decommissioning units one and two (62 MW and 57 MW, respectively) on Dec. 31, 2004. We plan to retire unit four (279 MW) in 2010 when its operating licence expires. The PPA for the plant expired on Dec. 31, 2003. Production in 2004 was sold on the spot market. The costs of decommissioning will reduce the Asset Retirement Obligation on the consolidated balance sheet.

Sale of Meridian Cogeneration Facility

On Dec. 1, 2004, we completed the sale of our 50 per cent interest in the 220 MW Meridian Cogeneration Facility located in Lloydminster, Saskatchewan to TA Cogen for its fair value of $110.0 million. TA Cogen financed the acquisition through the use of $50.0 million of cash on hand, by issuance of $30.0 million of units to each of TA Power and TransAlta Energy Corporation (TEC) and the issue of an advance to TEC for $30.0 million. We recorded a gain of $17.7 million ($11.5 million) or $0.06 per common share on an after-tax basis.

Sale of TransAlta Power Units

On Dec. 3, 2004, we sold our remaining 7.1 million units of TA Power at $9.00 each for net proceeds of $64.0 million, resulting in a gain of $20.6 million ($13.4 million) including a dilution gain of $11.6 million. We purchased these units in connection with our sale of the Sheerness Generating Station to TA Cogen in 2003.

Summerview Wind Farm

In the third quarter of 2004, we commissioned the 68 MW Summerview wind farm.

Prior Period Regulatory Decision

At Dec. 31, 2000, we provided US$28.8 million to account for potential refund liabilities relating to energy sales in California. On Dec. 12, 2002, a U.S. Federal Energy Regulatory Commission (FERC) Administrative Law Judge issued proposed findings of fact that recommended we refund US$9.0 million for electricity sales made to the California Independent System Operator (CAISO) and US$13.0 million for electricity sales made to the California Power Exchange (CALPX). In March 2003, FERC ordered the CAISO to review reference power and gas prices that are used to determine mitigated market clearing prices and refund obligations. On March 17, 2004, the CAISO released its preliminary adjusted prices. Based on these prices, the estimated refund liability we owed was US$46.0 million, being US$27.6 million to the CAISO, US$17.9 million to the CALPX and US$0.5 million to the Automated Power Exchange. Therefore, in March 2004, we recorded an additional pre-tax provision of US$17.2 million (Cdn$22.9 million). The after-tax impact was Cdn$14.9 million. The final adjusted prices were released in October 2004 and were substantially the same as those released on March 17, 2004.

FERC provided us with an opportunity to petition for relief from refund obligations. To be successful in such a petition for relief we were required to demonstrate that, as a result of the refund methodology, we suffered operating losses in respect of California transactions during the refund period. On Aug. 8, 2005, FERC issued an order detailing the methodology for a petition for relief from refund obligations. TransAlta prepared a petition for relief from the refund obligation and filed it with FERC. The CAISO and CALPX reviewed and commented on our petition and TransAlta replied to the CAISO and CALPX comments on Oct. 17, 2005. On Jan. 26, 2006, FERC conditionally accepted TransAlta's petition for relief, subject to modification. This revised compliance filing was due on Feb. 10, 2006. The outcome of this filing cannot be determined at this time. We will account for this only at the time that it is obtained from FERC.

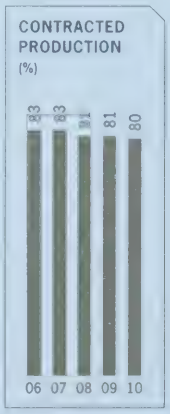
The impact of prior period regulatory decisions relating to prior reporting periods are recorded when the effect of such decisions are known, without adjustment to the financial statements of prior periods.

2006 OUTLOOK

The following factors will be influenced by, but not limited to, certain risks and uncertainties. For further discussion, see Risk Factors and Risk Management in this MD&A.

Production, Availability and Capacity

Based on our current operations, production capacity in 2006 is expected to be similar to 2005.



For 2006, we expect production to increase as a result of a full year of production from Genesee 3, Poplar Creek and unit four of the Wabamun plant. Availability is expected to increase slightly due to reduced planned maintenance primarily at our gas facilities.

Heavy rainfall in the Pacific Northwest experienced early in 2006 is affecting Centralia mine operations and power production in the short term. The impact of the abnormal rainfall on our ability to deliver coal to the plant to produce electricity is being partially offset by increasing coal imports, de-rating the plant when required, purchasing replacement power and running Centralia Gas when economically feasible. We are anticipating between 650 GWh to 950 GWh of lower production at the Centralia coal-fired plant during the first quarter of 2006.

Exposure to volatility in electricity prices and spark spreads is substantially mitigated through firm-price, long-term electricity sales contracts and hedging arrangements. For 2006, approximately 83 per cent of output is contracted, of which a significant portion relates to the Alberta PPAs, which are based on achieving specified availability rates. TransAlta continues to manage future price exposure as market liquidity exists.

Our existing production contracts have remaining terms ranging from one to 30 years with a weighted average remaining term of 12 years. Contracted production, as a percentage of potential production from existing assets, is shown for the next five years in the chart to the right.

If certain plants do not meet the availability or production targets specified in the PPAs or other long-term contracts, then the corporation must either compensate the purchaser for the loss in the availability of production or suffer a reduction in electrical or capacity payments. Consequently, an extended outage could have a material adverse effect on the business, financial condition, results of operations or cash flows of the corporation.

Production and gross margins from our merchant gas plants are subject to the changes in spark spreads discussed in the Power Prices section. TransAlta has not entered into fixed commodity contracts for gas for these merchant plants as gas will be purchased coincident in markets where spark spreads are adequate to profitably produce and sell electricity.

Power Prices

Electricity spot prices for 2006 are expected to be comparable to those experienced in 2005 in all markets. Our assumption is that 2006 gas prices will be similar to those achieved in 2005. Alberta and the Pacific Northwest markets should see minimal supply additions and good demand growth. Average hydro reservoir levels in the Pacific Northwest should keep power prices in both markets relatively unchanged year over year. In Ontario, additional nuclear supply should offset organic demand growth and leave prices and heat rates comparable year over year. Warm weather conditions during the summer could also impact demand. Overall, in 2006, spark spreads should remain relatively unchanged across all markets relative to 2005.

Spark spreads may not be completely correlated to natural gas prices due to the type and composition of generation that exists in the respective markets. Lower spark spreads are forecast to continue in Alberta and Ontario, while spark spreads are expected to remain relatively steady in the Pacific Northwest in 2006.

Fuel Costs

Mining coal is subject to cost increases due to inflation and diesel commodity prices, which the corporation seeks to mitigate through diesel hedges. Seasonal variations in coal mining are minimized through the application of standard costing.

The coal mines continue to be exposed to increasing input costs, higher amounts of overburden being removed and mining operations moving further away from the power plants. We expect these conditions to continue at Centralia until new areas of the mine are opened.

Exposure to gas costs for facilities under long-term sales contracts are minimized to the extent possible through long-term gas purchase contracts or corresponding offsets within revenues. Merchant gas facilities are exposed to the changes in spark spreads, discussed in the Power Prices section above. TransAlta has not entered into fixed commodity agreements for gas for these merchant plants as gas will be purchased coincident with spot pricing.

OM&A costs per MWh fluctuate by quarter and are dependent on the timing and nature of maintenance activities. OM&A costs per MWh in 2006 are expected to be consistent with 2005.

Capital and Maintenance Expenditures

Capital expenditures for 2006 are expected to be approximately $260 million to $275 million (excluding Mexico), of which approximately $110 million will be spent on major maintenance (excluding CE Generation LLC (CE Gen)) and $45 million will be spent on the Alberta and Centralia mines. The remainder will be spent at CE Gen and on productivity-related investments. Financing for these expenditures is expected to be provided by cash flow from operating activities.

Planned Maintenance

During 2006, we expect to spend between $165 million and $185 million on planned maintenance as outlined in the following table (excluding CE Gen):

	Coal	Gas and hydro	Total
Capitalized	$ 70–75	$ 30–35	$100–110
Expensed	65–70	0–5	65–75
	$135–145	$ 30–40	$165–185
GWh lost	2,250–2,300	200–225	2,450–2,525

We also expect to lose approximately 2,500 GWh of production due to planned maintenance during 2006.

Energy Marketing
Energy Marketing's trading activities are focused on real-time and short-term forward markets. Short-term forward markets show indications of increased volatility in the North American natural gas market. We will continue to prudently manage our risk profile utilizing value at risk (VAR) and other measures.

Our objective is for proprietary trading to contribute between $20 million and $40 million in annual operating income. In 2005, our Energy Marketing segment contributed $31.4 million of operating income (2004 – $8.1 million). Included in 2004 operating income is $22.9 million of provisions related to a prior period regulatory decision.

Net Interest Expense
Net interest expense for 2006 is expected to decline slightly compared to 2005 as a result of lower debt levels.

Income Tax Rate
Income tax rates in 2006 are expected to be consistent with 2005 levels. Assuming a similar geographic distribution of earnings and no material changes in tax rates, the corporation anticipates an effective tax rate for 2006 to be between 25 and 30 per cent.

Non-controlling Interests
Earnings attributable to non-controlling interests are expected to be slightly higher in 2006 due to lower depreciation charges as a result of the impairment of the Ottawa plant. Cash distributions are expected to be similar to 2005 levels.

Cash Requirements
In 2006, cash will be provided by a combination of cash flow from operations and utilization of various credit facilities. Cash will be required for maintenance, additions to PP&E, dividend payments and repayment of short-term and maturing senior debt.

Liquidity and Capital Resources
With the increased volatility in power and gas markets, market trading opportunities are expected to increase, which can potentially cause the need for additional liquidity. To mitigate this liquidity risk, the corporation maintains $1.8 billion of credit facilities and monitors exposures to determine any liquidity requirements.

Climate Change
We are positioning the company to meet the requirements of a Canadian climate change program should one be implemented by the Canadian Government. In addition to increasing production from renewable sources, we will manage climate change regulations through the continued investment in emission offset credits, development of clean coal technology, and internal efficiency improvements. We have reduced our worldwide greenhouse gas intensity by 11 per cent from 1990 levels while increasing our generating capacity by over 77 per cent. We also have a longer-term strategy to seek emission reduction opportunities as our existing plants are retired and as new combustion and environmental technology is developed to further reduce emissions.

As Canada's climate change program is not clear, we are not yet able to estimate the impact on our operations. However, the PPAs for our coal-fired plants in Alberta contain 'Change of Law' provisions that will provide for the recovery of compliance costs from our PPA customers.

The Kyoto Protocol is not expected to impact our U.S., Mexican or Australian operations.

SEGMENTED BUSINESS RESULTS

Generation *Owns and operates hydro, wind, geothermal, gas- and coal-fired plants and related mining operations in Canada, the United States, and Australia. At Dec. 31, 2005, Generation had 8,339 MW of gross generating capacity in operation (7,937 MW net ownership interest) and 540 MW under development.*

TransAlta has strategic alliances with EPCOR, ENMAX Corporation (ENMAX) and MidAmerican Energy Holdings Company (MidAmerican). The EPCOR alliance provided the opportunity for TransAlta to acquire a 50 per cent ownership in the 450 MW Genesee 3 project. TransAlta and ENMAX each own 50 per cent of the partnership in the McBride Lake wind farm. MidAmerican owns the other 50 per cent interest in CE Gen.

The results of the Generation segment were as follows:

	2005		2004		2003	
Year ended Dec. 31	**Total**	**Per MWh**	**Total**	**Per MWh**	**Total**	**Per MWh**
				(Restated, Note 1)		*(Restated, Note 1)*
Revenues	**$ 2,607.5**	**$ 50.33**	$ 2,341.7	$ 45.56	$ 2,304.8	$ 44.74
Fuel and purchased power	**(1,201.8)**	**(23.20)**	(1,031.7)	(20.07)	(990.8)	(19.23)
Gross margin	**1,405.7**	**27.13**	1,310.0	25.49	1,314.0	25.51
Operations, maintenance and administration	**507.1**	**9.79**	476.0	9.26	461.5	8.96
Depreciation and amortization	**354.9**	**6.85**	343.5	6.68	312.4	6.06
Taxes, other than income taxes	**21.3**	**0.41**	20.5	0.40	22.9	0.45
Operating expenses	**883.3**	**17.05**	840.0	16.34	796.8	15.47
Gain on sale of Meridian cogeneration facility	**–**	**–**	17.7	0.34	–	–
Gain on sale of TransAlta Power partnership units	**–**	**–**	44.8	0.87	15.2	0.30
Gain on sale of Sheerness Generating Station	**–**	**–**	–	–	191.5	3.72
Gain on sale of Seebe land	**–**	**–**	–	–	10.5	0.20
Asset impairment charges	**(36.2)**	**(0.70)**	–	–	(90.3)	(1.76)
Operating income before corporate allocations	**486.2**	**9.38**	532.5	10.36	644.1	12.50
Corporate allocations	**(76.4)**	**(1.47)**	(69.7)	(1.36)	(69.9)	(1.36)
Operating income	**$ 409.8**	**$ 7.91**	$ 462.8	$ 9.00	$ 574.2	$ 11.14
Production (GWh)	**51,810**		51,396		51,519	
Availability (%)	**89.4%**		89.2%		90.5%	

For the year ended Dec. 31, 2005, our availability was marginally improved at 89.4 per cent compared to 89.2 per cent in 2004, and lower than the 90.5 per cent recorded in 2003. The higher availability in 2003 was a result of higher availability at our Poplar Creek and Centralia facilities.

For the year ended Dec. 31, 2005, 82 per cent of our total production was subject to contracted prices (2004 – 83 per cent, 2003 – 91 per cent), with the remaining production subject to market pricing. Revenues received under contractual arrangements are not subject to short-term fluctuations in the spot price for electricity.

Generation's revenues are derived from the production of electricity and steam as well as ancillary services such as system support. In 2005, gas- and coal-fired facilities had exposure to market fluctuations in energy commodity prices representing 29 per cent and 4 per cent of our total generating capacity, respectively. We closely monitor the risks associated with these commodity price changes on our future operations and, where appropriate, use various physical and financial instruments to hedge our assets and operations from such price risk. These contracts are designated as effective hedge positions of future cash flows or fair values of the output and production of our owned assets. Under Canadian GAAP, settlement accounting is used for transactions that qualify for hedge accounting. Under U.S. GAAP, hedging activities are accounted for in accordance with Financial Accounting Standards Board (FASB) Statement 133.

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower as electricity prices generally increase in the winter months in the Canadian market. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring run-off and rainfall in the Canadian and U.S. markets.

Generation segment revenues are generated from the following revenue streams:

Alberta PPAs are long-term arrangements that apply to the previously regulated Alberta generation plants. Under the terms of a PPA, a single customer has the rights to the entire production of a plant or unit for the length of the PPA. All of our Alberta coal-fired and hydroelectric facilities operated under PPAs during 2005, except for the Wabamun and Genesee 3 plants. The PPA for the Wabamun plant expired on Dec. 31, 2003.

PPAs establish committed capacity and electrical energy generation requirements and availability targets to be achieved by each coal-fired plant, energy and ancillary services obligations for the hydroelectric plants, and the pricing formula at which capacity and power would be supplied. We bear the risk or retain the benefit of volume variances (except for those arising from events considered to be force majeure), and any change in costs required to maintain and operate the facilities. A component of the PPA capacity payment represents fixed operating, maintenance and fuel costs and is escalated annually based on certain indices published by Statistics Canada. The component of the capacity payment representing debt interest and a return on equity invested is subject to changes in the Canadian long-term bond rate.

Under the PPAs, we earn monthly capacity revenues, which are designed to recover fixed costs and provide a return on capital for our plants and mines. We also earn energy payments for the recovery of predetermined variable costs of producing energy, an incentive/penalty for achieving above/below the targeted availability and an excess energy payment for power production above committed capacity.

Our hydroelectric facilities are contracted in a single Alberta PPA that provides for energy and ancillary services revenues based on hourly targets. These targeted amounts are met by TransAlta through physical delivery or third party purchases.

Long-term contracts are similar to PPAs. We define a long-term contract as having an original term between 10 and 25 years. Long-term contracts are typically for gas-fired cogeneration plants and have between one and four customers per plant. Revenues are derived from payments for capacity and/or the production of electrical energy and steam.

Merchant revenue is derived from the sale of production only, with multiple customers per plant. Production is sold via: medium-term contract sales (typically two to 10 years); short-term asset-backed trading; and spot or short-term (less than one year) forward markets.

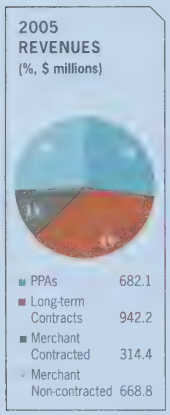
CE Gen earns revenues from 10 geothermal plants and three gas-fired facilities. Eight of the geothermal plants sell their output under long-term contracts expiring between 2016 and 2035. One facility is partially contracted while the remaining facility sells its output on the spot market but has an option to sell output under a 35-year contract based on market prices. The gas-fired facilities sell their output under fixed-price contracts ranging from three to 18 years of remaining contract life, with expiration dates of 2009 and 2024. All three facilities have gas supply arrangements in place for the duration of the electricity sales contracts.

Our production volumes, electricity and steam production revenues and fuel and purchased power costs are presented below:

Year ended Dec. 31, 2005	Production (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per MWh	Fuel & purchased power per MWh	Gross margin per MWh
Alberta PPAs	**25,279**	**$ 682.1**	**$ 201.6**	**$ 480.5**	**$ 26.98**	**$ 7.97**	**$ 19.01**
Long-term contracts	**6,947**	**647.9**	**392.7**	**255.2**	**93.26**	**56.53**	**36.73**
Merchant	**16,630**	**983.2**	**535.2**	**448.0**	**59.12**	**32.18**	**26.94**
CE Gen	**2,954**	**294.3**	**72.3**	**222.0**	**99.63**	**24.48**	**75.15**
	51,810	**$ 2,607.5**	**$ 1,201.8**	**$ 1,405.7**	**$ 50.33**	**$ 23.20**	**$ 27.13**

Year ended Dec. 31, 2004 *(Restated, Note 1)*	Production (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per MWh	Fuel & purchased power per MWh	Gross margin per MWh
Alberta PPAs	25,836	$ 679.2	$ 187.9	$ 491.3	$ 26.29	[illegible]	$ 19.02
Long-term contracts	7,183	581.9	341.9	240.0	81.01	[illegible]	33.41
Merchant	15,676	799.5	435.2	364.3	51.00	27.76	23.24
CE Gen	2,701	281.1	66.7	214.4	104.07	24.69	79.38
	51,396	$ 2,341.7	$ 1,031.7	$ 1,310.0	$ 45.56	$ 20.07	$ 25.49

Year ended Dec. 31, 2003 *(Restated, Note 1)*	Production (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per MWh	Fuel & purchased power per MWh	Gross margin per MWh
Alberta PPAs	28,295	$ 758.8	$ 191.3	$ 567.5	$ 26.82	$ 6.76	$ 20.06
Long-term contracts	6,923	552.8	324.2	228.6	79.85	46.83	33.02
Merchant	13,683	684.2	394.9	289.3	50.00	28.86	21.14
CE Gen	2,618	309.0	80.4	228.6	118.03	30.71	87.32
	51,519	$ 2,304.8	$ 990.8	$ 1,314.0	$ 44.74	$ 19.23	$ 25.51



Alberta PPAs

Production in 2005 of 25,279 GWh from our PPA facilities was 557 GWh lower than 2004, primarily due to higher planned maintenance on these assets during the year resulting in an incremental 267 GWh of lost electricity production.

Production for the year ended Dec. 31, 2004 decreased by 2,459 GWh compared to 2003, primarily due to the Wabamun plant now being classified as merchant (2,940 GWh) and higher unplanned outages at the remaining Alberta Thermal plants (168 GWh), partially offset by reduced planned maintenance (642 GWh).

Revenues for 2005 were essentially flat compared to 2004, as the higher pricing experienced in 2005 was offset by the net penalties paid during both planned and unplanned outages.

Revenues for the year ended Dec. 31, 2004 decreased by $79.6 million compared to the same period in 2003 due to the Wabamun plant now being classified as merchant ($92.2 million) and by higher unplanned outages ($34.2 million), partially offset by reduced penalties related to planned maintenance at the remaining Alberta Thermal plants ($53.0 million).

On a per MWh basis, revenues were consistent between 2005, 2004 and 2003.

Our fuel cost per MWh increased $0.70 to $7.97 per MWh in 2005. This increase is primarily a result of escalations in diesel pricing related to mine operations, the majority of which is ultimately recovered from our PPA customers through escalation mechanisms in the PPAs.

For the year ended Dec. 31, 2004, fuel costs increased by $0.51 per MWh compared to the same period in 2003 due to higher diesel prices, increased overburden removal costs and decreased coal volumes. Substantially all of the coal used for production under Alberta PPAs is from coal reserves owned by TransAlta.

Long-term Contracts

Long-term contract volumes declined 236 GWh to 6,947 GWh in 2005 due to planned maintenance and reduced customer demand at certain of our gas-fired facilities. In the year ended Dec. 31, 2004, production increased by 260 GWh compared to the same period in 2003 due to increased production at Sarnia and our wind farms and lower unplanned outages at the Mississauga, Ottawa and Windsor-Essex plants.

In 2005, our revenue per MWh increased $12.25 per MWh. Higher natural gas prices drove fuel and purchased power per MWh to $56.53, an increase of $8.93 per MWh, and had a positive impact on our realized electricity prices.

Revenues increased by $1.16 per MWh in 2004 compared to 2003, primarily due to increased natural gas costs that were passed on to the customer. Fuel and purchased power increased by $0.77 per MWh due to higher market prices for natural gas.

On an overall basis, our margins increased $15.2 million in 2005 due to increased thermal volumes at Sarnia and revised contract pricing at some of our gas plants. On a per MWh basis, margins increased $3.32.

For the year ended Dec. 31, 2004, gross margin increased by $11.4 million compared to the same period of 2003, primarily due to increased indices at Australia. On a per MWh basis, a modest increase of $0.39 was realized.

Merchant Production

Record high natural gas prices in 2005 had a favourable impact on pricing and spark spreads in all regions. In 2004, electricity spot prices in the Alberta and Ontario markets decreased while the Mid-Columbia price increased compared to 2003. Spark spreads decreased in 2004 compared to 2003 in both Alberta and the Ontario markets, but increased in the Pacific Northwest market.

Merchant production increased 954 GWh to 16,630 GWh due to the commissioning of Genesee 3, increased hydro production due to higher rainfall in 2005 and low reservoir levels in 2004 and incremental production from unit four at our Wabamun plant, which underwent a major maintenance outage in 2004. These increases were partially offset by the lost production

due to the CN train derailment, the decommissioning of units one and two of our Wabamun plant and reduced customer demand and major maintenance at Poplar Creek.

For the year ended Dec. 31, 2004, merchant production was 15,676 GWh, of which 6,718 GWh was contracted. For the same period in 2003, merchant production was 13,683 GWh, of which 8,996 GWh was contracted. The increase was due to the PPA at our Wabamun plant expiring in 2003 and the production from this facility being sold on the merchant market and incremental production from Sarnia in the first quarter, partially offset by decreased production at Centralia and lower dispatching from the merchant gas plants.

Merchant revenues were significantly impacted by increases in natural gas prices in 2005. The combination of this price impact and increased production drove revenues $183.7 million higher in 2005. Offsetting this in gross margins is the impact of rising costs of fuel and purchased power of $100.0 million. The net impact on our margins was $83.7 million. The commissioning of Genesee 3, incremental margins from unit four of Wabamun, net of the CN train derailment, increased hydro production and pricing and recontracting at our Centralia coal-fired facility were partially offset by the decommissioning of units one and two at Wabamun. At our Centralia coal-fired facility, higher pricing had a favourable impact on revenues, however, the impact of diesel escalations, tire shortages and delays in permitting had a negative impact on fuel and purchased power. Merchant revenues increased to $59.12 per MWh from $51.00 in 2004. On a per MWh basis, fuel and purchased power increased from $27.76 to $32.18 in 2005.

In 2004, merchant revenues increased by $115.3 million, fuel and purchased power increased by $40.3 million and gross margins increased by $75.0 million compared to the same period in 2003. These gross margin increases were due to incremental production from the Wabamun plant partially offset by lower production and shrinking spark spreads at Centralia and Poplar Creek. Merchant revenues increased by $1.00 per MWh while fuel and purchased power decreased by $1.10 per MWh compared to the same period in 2003.

CE Gen

During 2005, production from CE Gen increased by 253 GWh to 2,954 GWh due primarily to increased availability from the Imperial Valley and Saranac facilities. As a result, revenues and cost of fuel also increased. On a per MWh basis, however, the impact of the devaluation of the U.S. dollar relative to the Canadian dollar drove revenue per MWh to $99.63 from $104.07 and cost of fuel and purchased power to $24.48 from $24.69.

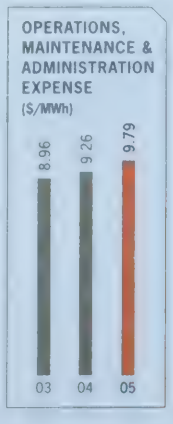
TransAlta's share of CE Gen's production for 2004 increased by 83 GWh compared to 2003. This was the result of increased availability due to reduced planned maintenance and increased production at Imperial Valley partially offset by decreased production at the Power Resources facility following the expiration of the long-term contract in September 2003.

In 2004, revenues decreased by $13.96 per MWh compared to the same period in 2003 due to the expiration of the Power Resources facility's long-term contract and the strengthening of the Canadian dollar compared to the U.S. dollar. In 2004, fuel and purchased power decreased by $6.02 per MWh compared to the same period in 2003 primarily due to the gas remarketing arrangement at the Saranac plant in the first quarter of 2004 and the strengthening of the Canadian dollar compared to the U.S. dollar, partially offset by increased fuel prices at the Yuma and Saranac facilities in 2004.

OM&A Expense

Our OM&A costs increased $31.1 million or $0.53 per MWh, in 2005 to $507.1 million or $9.79 per MWh, due to the addition of Genesee 3, certain cost escalations that pass through to our customers under the PPAs, increased compensation costs related to incentives and cost escalations related to materials.

For the year ended Dec. 31, 2004 OM&A increased by $14.5 million ($0.30 per MWh) due in part to incremental operating costs related to our Sarnia plant. Additionally, in 2003, OM&A costs were reduced as a result of the reversal of a pension over-accrual and a decrease in expected performance share ownership plan payouts due to market conditions.



Planned Maintenance

The table below shows the amount of planned maintenance capitalized and expensed, excluding CE Gen:

	2005	2004 (Restated, Note 1)	2003 (Restated, Note 1)
Capitalized	$ 119.1	$ 88.1	$ 35.2
Expensed	68.3	73.0	76.1
	$ 187.4	$ 161.1	$ 111.3

Our major maintenance activity in 2005 resulted in lost production of 2,818 GWh, compared to 2,507 GWh in 2004 and 2,159 GWh in 2003.

The increase in capitalized maintenance of $31.0 million in 2005 relates to the completion of four "C" inspections completed on our gas units during the year.

In 2004, capitalized maintenance increased by $52.9 million while operating maintenance decreased by $3.1 million as compared to the same period in 2003 due to spending on capital replacement activities rather than repair activities in coal outages and gas outages with no comparable amounts in 2003 for gas outages due to recent additions to the gas fleet.

Annually, we purchase long lead materials for future years' outages as lead times on these items can extend well beyond one year. In 2005, $6.2 million was spent on such items, compared to $19.8 million in 2004. These items are not included in the planned maintenance chart.

Depreciation and Amortization

Depreciation and amortization increased by $11.4 million in 2005 due to the addition of Genesee 3 and equipment retired during planned maintenance activities.

In 2004, depreciation expense increased by $31.1 million, primarily due to incremental depreciation from our Sarnia plant, increased depreciation from CE Gen, increased depreciation from our Ottawa, Mississauga and Windsor-Essex plants and increased capital spending on planned maintenance.

Taxes Other than Income Taxes

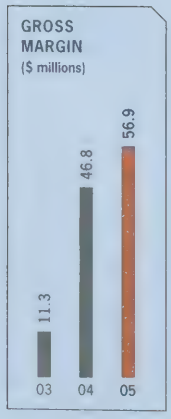
In 2005, taxes other than income taxes were consistent with both 2004 and 2003.

Energy Marketing *Derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives not supported by TransAlta-owned generation assets. Energy Marketing also utilizes contracts of various durations for the forward sales of electricity and purchases of natural gas and transmission capacity to effectively manage available generating capacity and fuel and transmission needs on behalf of Generation. These results are included in the Generation segment. Key performance indicators for Energy Marketing's proprietary trading include trading volumes, margins and VAR.*

Energy Marketing is vital to delivering sustainable revenues. Energy Marketing acts to maximize margins from the production and sale of electricity, minimize the cost of natural gas used to generate electricity and steam and reduce the risk to the corporation from unplanned outages by acquiring replacement power at the lowest possible price.

Energy Marketing uses commodity derivatives to manage risk, earn trading revenue and gain market information. The portfolio consists of physical and financial derivative instruments including forwards, swaps, futures and options in various commodities. These contracts meet the definition of trading activities and have been accounted for using fair values for both Canadian and U.S. GAAP. Changes in the fair values of the portfolio are recognized in income in the period they occur.

In compliance with FASB Emerging Issues Task Force (EITF) 03-11, *Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes* as defined in Issue No. 02-3, we have concluded that energy trading contracts settled in the real-time physical markets meet the definition of derivative contracts held for delivery and therefore revenues from these contracts are reported on a gross basis (trading revenues and trading purchases are shown separately) in the consolidated statement of earnings.



The results of the Energy Marketing segment are as follows:

Year ended Dec. 31	2005	2004	2003
Revenues	**$ 231.0**	$ 244.5	$ 108.7
Trading purchases	**(174.1)**	(197.7)	(97.4)
Gross margin	**56.9**	46.8	11.3
Operations, maintenance and administration	**12.5**	5.3	14.9
Depreciation and amortization	**1.7**	2.0	3.1
Prior period regulatory decision	**–**	22.9	–
Operating income before corporate allocations	**42.7**	16.6	(6.7)
Corporate allocations	**(11.3)**	(8.5)	(8.8)
Operating income	**$ 31.4**	$ 8.1	$ (15.5)

Gross margins increased $10.1 million in 2005 due primarily to strong results from trading activities in our Western region and gains on our gas positions throughout the year.

Gross margin increased by $35.5 million in 2004 compared to the same period in 2003. In the second quarter of 2003, Energy Marketing realized a $33.3 million (US$20.0 million) pre-tax loss on TCCs.

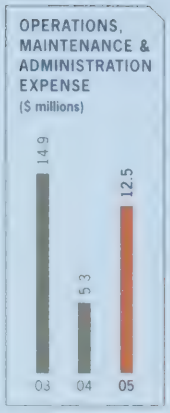
As a result of the increased margins generated during 2005, our OM&A costs have increased due to higher incentive compensation costs as well as project consulting expenses incurred during the year.

A $9.6 million reduction in OM&A was realized in 2004 compared to 2003 as we consolidated our Annapolis office with Calgary, resulting in lower staffing levels.

Depreciation and amortization was relatively consistent with 2004. The reduction in 2004 over 2003 is a result of the closure of the Annapolis office.

VAR is a measure to manage earnings exposure for Energy Marketing activities. The average daily VAR in fiscal 2005 was approximately $3.6 million compared to $3.8 million in 2004. See additional discussion under commodity price risk in Risk Factors and Risk Management.

At Dec. 31, 2005, we had a US$51.4 million receivable relating to energy sales in California. As previously discussed in Significant Events, a provision of US$28.8 million to account for potential refund liabilities was recorded in December 2000. On March 17, 2004, the CAISO released its preliminary adjusted prices indicating that our refund liability is now US$46.0 million. Based on these preliminary refund estimates, in the first quarter of 2004 we increased our provision for potential refund liabilities by US$17.2 million (Cdn$22.9 million) to US$46.0 million. The final adjusted prices were released in October 2004 and were substantially the same as those released on March 17, 2004. Based on an Aug. 8, 2005 FERC order, TransAlta prepared a petition for relief from the refund obligation and filed it with FERC. On Jan. 26, 2006, FERC conditionally accepted TransAlta's petition for relief, subject to modification. This revised compliance filing was due on Feb. 10, 2006.



TransAlta's fixed price trading positions were as follows:

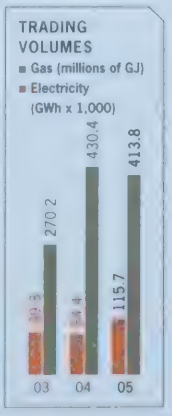
Units (000s)	Electricity (MWh)	Natural gas (GJ)
Fixed price payor, notional amounts, Dec. 31, 2005	**19,315**	**11,126**
Fixed price payor, notional amounts, Dec. 31, 2004	14,029	13,422
Fixed price receiver, notional amounts, Dec. 31, 2005	**19,047**	**12,158**
Fixed price receiver, notional amounts, Dec. 31, 2004	13,558	12,277
Maximum term in months, Dec. 31, 2005	**24**	**12**
Maximum term in months, Dec. 31, 2004	24	12

Proprietary trading encompasses a range of contractual terms spanning from short-term speculative trading of one to 24 months to longer-term marketing transactions with potential terms greater than 24 months. Changes in trading positions from Dec. 31, 2004 to Dec. 31, 2005 are due to changing market conditions and corresponding regional strategy positioning.

Gross physical and financial settled sales of proprietary trading transactions are as follows:

Year ended Dec. 31 Electricity (GWh)	2005	2004	2003
Physical	**58,016**	61,165	55,506
Financial	**57,666**	23,239	34,327
	115,682	84,404	89,833

Year ended Dec. 31 Gas (million GJ)	2005	2004	2003
Physical	**86.9**	122.4	100.1
Financial	**326.9**	308.0	170.1
	413.8	430.4	270.2



In 2005, the emergence of additional counterparties in the financial markets greatly increased market liquidity and thus our financial volumes of electricity and gas increased considerably over 2004. Our trading activities continue to be subject to the prudent controls and procedures they have been subject to in prior years, as described in Commodity Price Risk on page 56 of this MD&A.

Physical electricity volumes were consistent with those in 2004. Fluctuations in physical gas volumes traded are a result of price volatility in 2005.

In 2004, financial electricity volumes were lower than the same period in 2003 due to the elimination of trading in New York TCCs in 2003. Physical electricity volumes were higher in 2004 compared to [illegible]

development of Eastern region real-time markets. Our power trading strategies consist of shorter-term physical and financial trades in regions where we have assets and the markets that interconnect with those regions.

In accordance with EITF 02-03, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, physical transmission and physical gas in storage are accounted for using accrual accounting. At Dec. 31, 2005, TransAlta recorded prepaid transmission contract assets of $0.8 million compared to approximately $1.5 million at Dec. 31, 2004. The transmission contracts relate to the period from April 2005 to March 2006 and are amortized over this period. Physical transmission is widely used in the California market with a maximum contract term of 12 months. At Dec. 31, 2005, physical gas in storage was recorded at $5.2 million. Forward power and gas transactions utilizing physical transmission and gas in storage are accounted for on a mark-to-market basis. While the physical and forward positions economically offset, some unrealized earnings exposure may result in the interim period prior to settlement.

PRICE RISK MANAGEMENT

Our price risk management assets and liabilities represent the value of unsettled (unrealized) proprietary trading transactions and certain asset backed trading transactions accounted for on a fair value basis. With the exception of transmission contracts, the fair value of all energy trading activities is based on quoted market prices. The fair value of financial transmission contracts is based upon statistical analysis of historical data. All transmission contracts are accounted for in accordance with EITF 02-03. The following tables show the balance sheet classifications for price risk management assets and liabilities as well as the changes in the fair value of the net price risk management assets for the period:

Year ended Dec. 31	2005	2004
Balance Sheet		
Price risk management assets		
Current	**$ 63.8**	$ 41.9
Long term	**13.8**	11.3
Price risk management liabilities		
Current	**(58.3)**	(27.7)
Long term	**(8.6)**	(10.0)
Net price risk management assets outstanding	**$ 10.7**	$ 15.5

	Fair value
Change in fair value of net assets	
Net price risk management assets outstanding at Dec. 31, 2004	$ 15.5
Contracts realized, amortized or settled during the year	(24.4)
Changes in values attributable to market price and other market changes	6.1
New contracts entered into during the current calendar year	13.5
Net price risk management assets outstanding at Dec. 31, 2005	**$ 10.7**

For the year ended Dec. 31, 2005, our net price risk management assets and liabilities decreased $4.8 million compared to the same period in 2004 primarily due to contracts settled during the year offset partially by new contracts entered in 2005 and value changes associated with contracts in existence at both year ends. Changes in net price risk management assets and liabilities are generally reflected within the gross margin of both Energy Marketing and Generation business segments.

The source of the valuations of the above contracts and maturities over each of the next five calendar years and thereafter is as follows:

	2006	2007	2008	2009	2010	2011 and thereafter	Total
Prices actively quoted	$ 1.6	$ 1.0	$ 2.1	$ 1.3	$ 0.8	$ –	$ 6.8
Prices based on models	3.9	–	–	–	–	–	3.9
	$ 5.5	$ 1.0	$ 2.1	$ 1.3	$ 0.8	$ –	$ 10.7

Our proprietary trading activities are mainly short-term transactions under 24 months in duration, thereby limiting credit risk and maintaining low working capital requirements. Transactions extending past 2006 are Generation asset-backed contracts that do not qualify for hedge accounting and have a low risk profile including long-term fixed for floating power swaps and a heat rate swap.

NET INTEREST EXPENSE

Year ended Dec. 31	2005	2004	2003
		(Restated, Note 1)	(Restated, Note 1)
Interest on recourse and non-recourse debt	$ 184.2	$ 192.8	$ 222.8
Interest on preferred securities	16.5	44.5	36.8
Interest income	(8.7)	(9.9)	(4.5)
Capitalized interest	(3.4)	(20.0)	(43.0)
Net interest expense	$ 188.6	$ 207.4	$ 212.1

Our net borrowing costs were lower in 2005 than 2004. In the first quarter of 2005, we redeemed $300.0 million of our preferred securities and replaced this with lower interest rate borrowings. Capitalized interest has been reduced as a result of the commissioning of Genesee 3 in March 2005.

Our 2004 borrowing costs were lower than 2003 due to reductions in overall debt levels and lower interest rates. The interest on preferred securities includes the $7.6 million charge we recognized in 2004 related to the redemption of the $300.0 million noted above at the time we made the decision to redeem these securities. Capitalized interest decreased in 2004 due to the commencement of operations at the Sarnia facility in 2003, offset by interest on the construction of the Summerview wind farm and Genesee 3. Interest income is primarily from interest earned on deposits with various taxation authorities.

EQUITY LOSS

Year ended Dec. 31	2005	2004	2003
Equity loss	$ (0.9)	$ (8.5)	$ (6.0)

As discussed in the New Accounting Standards section of this MD&A on page 61, we no longer consolidate the results of our Mexican plants, Campeche and Chihuahua.

The equity loss realized on the Mexican plants declined from $8.5 million in 2004 to $0.9 million in 2005. Capacity payments increased in 2005 compared to 2004 as a result of lower unplanned outages at the Chihuahua facility. Production, however, declined by approximately 13 per cent as production at the Chihuahua plant was curtailed at the request of the Comisión Federal de Electricidad (CFE). The curtailment of production does not significantly impact earnings as gas costs are passed through to the CFE and we continue to receive our capacity payments. The devaluation of the U.S. dollar compared to the Canadian dollar partially offset the benefit of the higher availability. Interest expense on the non-recourse debt at the Campeche facility declined due to scheduled debt repayments.

The equity loss increased from $6.0 million in 2003 to $8.5 million in 2004 as a result of a full year of interest expense related to the non-recourse debt at the Campeche facility and a full year of depreciation expense at both facilities, which were commissioned in 2003.

INCOME TAXES

Year ended Dec. 31	2005	2004	2003
Income tax expense	$ 47.4	$ 49.1	$ 64.3
Effective tax rate (%)	20.2	23.4	21.5

Income tax expense for 2005 was $47.4 million, consistent with 2004. Included in income tax expense is $13.0 million related to a favourable settlement of outstanding disputes with income tax authorities. Included in income tax expense for 2004 is $6.8 million related to a tax settlement at our New Zealand operations. Income tax expense for 2003 includes the impact of the taxation on the sale of the Sheerness Generating Station, the recognition of deferred gain and impairment charges. Adjusting for these items, our effective income tax rate was 26 per cent for 2005, compared to 27 per cent in 2004 and 29 per cent in 2003.

We constantly monitor our outstanding tax positions and are in regular contact with various income tax authorities.

NON-CONTROLLING INTERESTS

Year ended Dec. 31	2005	2004	2003
Non-controlling interests	**$ 18.5**	$ 46.0	$ 34.2

Included in non-controlling interests in 2005 is a $36.2 million recovery related to the impairment of the Ottawa facility that is attributable to the non-controlling interests. Adjusting for this amount, non-controlling interests increased to $54.7 million. The increase is attributable to our disposition of our remaining 7.1 million units of TA Power, acquired on the disposition of the Sheerness Generating Station to TA Cogen in 2003.

The $11.8 million increase in non-controlling interests from 2003 to 2004 is a result of the disposition of the Sheerness Generating Station to TA Cogen in the third quarter of 2003.

CONSOLIDATED BALANCE SHEETS

The following chart outlines significant changes in the consolidated balance sheets between Dec. 31, 2005 and Dec. 31, 2004:

	Increase/ (decrease)	Explanation
Cash and cash equivalents	$ (21.9)	Refer to Consolidated Statements of Cash Flows.
Accounts receivable	170.9	Increased Energy Marketing trading and increased Generation and CE Gen activity mainly due to increased prices and incremental revenues from Genesee 3.
Price risk management assets (current)	21.9	Fluctuations in the volumes of power contracts receivable and an increase in prices.
Prepaid expenses	23.5	Increase in deferred stripping costs.
Property, plant and equipment, net of accumulated depreciation	(157.1)	Decrease due to depreciation offset by capital additions.
Intangible assets	(42.5)	Amortization of the CE Gen sales contracts and change in foreign exchange rates.
Other assets (including current portion)	(289.8)	Decrease in mark-to-market changes on hedging derivatives.
Short-term debt	(21.3)	Net decrease of short-term debt.
Accounts payable and accrued liabilities	147.7	Increase in trading activity in Energy Marketing, timing of planned maintenance projects and pension accruals.
Dividends payable	31.2	Increase due to timing of payment of dividends.
Price risk management liabilities (current)	30.6	Fluctuations in the volumes of power contracts payable and an increase in prices.
Recourse long-term debt (including current portion)	(236.7)	Repayment of long-term debt, redemption of $300.0 million preferred securities, lower debt balances due to foreign exchange rate changes, partially offset by $200.0 million bond issue.
Non-recourse long-term debt (including current portion)	(59.5)	Repayment of long-term debt and changes to foreign exchange rates.
Deferred credits and other long-term liabilities (including current portion)	(267.1)	Decrease is mainly due to scheduled maturities of net investment hedge contracts.
Net Future income tax assets and liabilities (including current portions)	23.3	Increase in income tax deductions in excess of recorded depreciation of PP&E, offset by increase in unused tax losses that are expected to be recovered in future years.
Non-controlling interests	(57.8)	Decrease is due mainly to impairment of the Ottawa facility.
Shareholders' equity	73.1	Issuance of common shares offset by dividend declarations and tax provisions on hedging gains/losses.

CONSOLIDATED CASH FLOW STATEMENTS

The following chart outlines significant changes in the consolidated cash flow statements between Dec. 31, 2005 and Dec. 31, 2004:

Year ended Dec. 31	2005	2004	Explanation
		(Restated, Note 1)	
Cash and cash equivalents, beginning of period	**$ 101.2**	$ 123.8	
Provided by (used in):			
Operating activities	**619.4**	591.2	Increased earnings offset by higher working capital requirements.
Investing activities	**(242.1)**	(57.4)	Net capital expenditures of $323.9 million and an increase in the Mexican investment were partially offset by realized gains on foreign exchange forwards and intercompany loans of $90.0 million. In 2004, capital expenditures of $268.1 million relating primarily to the construction of the Summerview wind farm, the Genesee 3 project, and major maintenance, partially offset by proceeds from the exercise of TA Power warrants ($61.7 million) and the collection of the $90.8 million Zinc Recovery long-term receivable.
Financing activities	**(396.3)**	(549.3)	Issuance of $200 million of senior unsecured notes, common share issuances of $20.0 million, and repayments on an advance to TA Power of $24.0 million were used to fund redemption of preferred securities of $300.0 million, repayment of short- and long-term borrowings of $163.0 million, non-controlling interest distributions of $78.0 million, and dividend payments of $99.2 million. In 2004, net repayment of short-term debt of $72.9 million, net repayment of long-term debt of $135.1 million, cash dividends on common shares of $102.6 million, and non-controlling interest distributions of $33.5 million.
Translation of foreign currency cash	**(2.9)**	(7.1)	
Cash and cash equivalents, end of period	**$ 79.3**	$ 101.2	

The following chart outlines significant changes in the consolidated balance sheets between Dec. 31, 2004 and Dec. 31, 2003:

Year ended Dec. 31	2004	2003	Explanation
	Restated, Note 1	*Restated, Note 1*	
Cash and cash equivalents, beginning of period	$ 123.8	$ 137.2	
Provided by (used in):			
Operating activities	591.2	474.3	In 2004, improved non-cash working capital balances and increased cash earnings. In 2003, increased cash earnings and the collection of commodity tax receivables in Mexico and the U.S. of US$79.0 million.
Investing activities	(57.4)	(315.0)	In 2004, capital expenditures of $345.7 million including completion of Summerview wind farm and the Genesee 3 plant and major maintenance, partially offset by $116.5 million in proceeds from the sale of TA Power partnership units, the collection of the $90.8 million Zinc Recovery long-term receivable and $47.8 million in realized gains on net investment hedges. In 2003, capital expenditures of $434.4 million related to the construction of Genesee 3, the acquisition of CE Gen for $323.4 million (net of cash acquired of $43.2 million), offset by $194.1 million in realized gains on net investment hedges, proceeds on sale of the Sheerness plant ($149.9 million), the Goldfields pipeline ($21.6 million), the head office building ($65.8 million), the Seebe land ($11.0 million) and exercise of TA Power warrants ($37.2 million). The remainder of the cash flow was primarily related to the reduction of restricted cash.
Financing activities	(549.3)	(165.5)	In 2004, repayment of short-term debt of $85.4 million, net repayment of long-term debt of $282.0 million, cash dividends on common shares of $135.4 million and minority interest distributions of $48.4 million. In 2003, repayment of short-term debt of $170.2 million, net repayment of long-term debt of $56.5 million, cash dividends on common shares of $158.3 million (net of dividend reinvestments of $54.6 million) and minority interest distributions of $38.9 million were partially offset by net proceeds on the issuance of common shares of $265.0 million.
Translation of foreign currency cash	(7.1)	(7.2)	
Cash and cash equivalents, end of period	$ 101.2	$ 123.8	

LIQUIDITY AND CAPITAL RESOURCES

At the corporate level, we raise substantially all external capital to be invested in the various business units and affiliated or subsidiary companies as required. This strategy allows us to gain access to sufficient capital at the lowest overall cost to finance growth opportunities and provide financial flexibility. Historically, external financing has been obtained from borrowings under credit facilities, proceeds from the disposal of non-core assets and the issuance of debt, preferred securities and equity. Internally, capital is also raised through operations. A summary of cash flows is as follows:

Year ended Dec. 31	2005	2004	2003
		(Restated, Note 1)	*(Restated, Note 1)*
Cash and cash equivalents, beginning of year	**$ 101.2**	$ 123.8	$ 137.2
Cash flow from (used in):			
Operating activities	**619.4**	591.2	474.3
Investing activities	**(242.1)**	(57.4)	(315.0)
Financing activities	**(396.3)**	(549.3)	(165.5)
Translation of foreign currency cash	**(2.9)**	(7.1)	(7.2)
Cash and cash equivalents, end of year	**$ 79.3**	$ 101.2	$ 123.8

In the first quarter of 2005, we redeemed $300.0 million in preferred securities, which carried an average interest rate of 7.77 per cent. This redemption was financed through short-term borrowings. In the fourth quarter of 2005, we repaid $83.4 million of long-term debt. This repayment was funded with short-term debt. Also in the fourth quarter, the maturity date of $141.1 million of bonds was extended to 2030 at an interest rate of 6.9 per cent.

In the fourth quarter of 2005, we issued $200.0 million of two-year, 4.20 per cent senior unsecured notes.

In November 2005, we renewed our $1.0 billion medium-term note shelf registration. We also increased our committed bank credit facility to $1.5 billion from $1.2 billion in July 2003 in order to increase our liquidity. We maintain approximately $330 million of uncommitted credit facilities. At Dec. 31, 2005, we had approximately $1.2 billion of credit available from our committed and uncommitted credit facilities.

In November 2003, we issued US$300.0 million of 10-year senior notes under a US$1.0 billion shelf registration statement filed May 14, 2002. The notes bear interest at 5.75 per cent per annum. Proceeds from the issuance were primarily used to refinance bonds that matured in 2003. In July 2004, we renewed this US$1.0 billion shelf registration.

Operating Activities

Operating activities after changes in non-cash working capital provided cash of $619.4 million in 2005 compared to $591.2 million in 2004 and $474.3 million in 2003. The increase in 2005 is due primarily to increased cash earnings. The increase in 2004 is primarily due to increased cash earnings and lower working capital requirements.

Investing Activities

Investing activities used cash of $242.1 million in 2005 compared to $57.4 million in 2004 and $315.0 million in 2002.

In 2005, we added $325.5 million to our capital assets through planned maintenance, the completion of Genesee 3 and additions to our fleet of mining equipment.

In 2004, additions to capital assets totaled $345.7 million and consisted primarily of completion of the Summerview wind farm, continuing construction of the Genesee 3 project and capitalized planned maintenance.

Cash provided by disposals and the sale of capital assets in 2005 was $1.6 million. In 2004, $116.5 million of proceeds from the sale of TA Power partnership units, $24.2 million received on the sale of the Meridian Cogeneration Facility and $11.7 million from the sale of other capital assets was provided.

Cash provided by disposals and the sale of capital assets in 2003 was $285.5 million, comprised of $149.9 million received from the sale of the Sheerness Generating Station, $65.8 million of proceeds from the sale of the head office building, $37.2 million of proceeds from the sale of TA Power partnership units, $21.6 million of proceeds from the sale of the Goldfields pipeline and $11.0 million of proceeds from the sale of the Seebe land.

Financing Activities

Financing activities used cash of $396.3 million compared to $549.3 million in 2004 and $165.5 million in 2003.

In 2005, we repaid $162.9 million of debt, redeemed $300.0 million in preferred securities and issued $200.0 million in two-year 4.20 per cent notes. We paid cash dividends of $99.2 million in 2005 and distributed $77.5 million to our subsidiaries' non-controlling interests. Our cash dividends for 2005 include only three quarters of payment as the fourth quarter dividend, although declared in the fourth quarter, was not paid until January 2006.

In 2004, we reduced long-term debt by $282.0 million, reduced short-term debt by $85.4 million, paid cash dividends on common shares of $135.4 million and non-controlling interest distributions of $48.4 million, some of which were funded from cash flow from operating activities.

In 2003, net proceeds on the issuance of common shares of $265.0 million were more than offset by net long-term debt repayment of $56.5 million, net repayment of short-term debt of $170.2 million, cash dividends on common shares of $158.3 million, and non-controlling interest distributions of $38.9 million, some of which were funded from cash flow from operating activities.

In 2003, TransAlta repaid $350.0 million of senior secured debt of TransAlta Utilities Corporation.

In 2005, under the terms of the Normal Course Issuer Bid, the corporation purchased no common shares for cancellation (2004 – 143,500; 2003 – nil).

TransAlta's dividends per common share were $1.00 in 2005, 2004 and 2003.

Financing Arrangements

TransAlta raises capital in the Canadian and U.S. markets. TransAlta has the following financing arrangements in place:

- US$1.0 billion shelf registration program; no amount has been issued since its renewal in July 2004. This program remains valid until August 2006 and is expected to be renewed;
- $1.0 billion medium-term note program; $200.0 million was drawn under this program in December 2005. This program remains valid until December 2007;
- A $200.0 million commercial paper program of which $12.5 million was issued at Dec. 31, 2005;
- $1.5 billion committed syndicated bank credit facility, with $433.4 million utilized at Dec. 31, 2005. This facility was renewed in April 2005 and expires in June 2008; and
- $332.0 million of additional bank credit facilities, with $261.2 million utilized at Dec. 31, 2005. All of these facilities are non-committed.

At Dec. 31, 2005, the corporation had approximately $1.2 billion of credit available from its committed and uncommitted credit facilities.

In addition to the above, the corporation has US$121.5 million of non-recourse project financing for the Campeche project. This amount is not included in long-term debt on our consolidated balance sheet as our Mexican operations are Variable Interest Entities (VIE). See page 61 for a discussion of the change in this accounting standard. It is the corporation's expectation that future financing requirements, including financing requirements in foreign jurisdictions, will be met primarily through raising capital at the TransAlta Corporation level.

At Dec. 31, 2005, TransAlta had a working capital ratio of 0.81 compared to 0.76 at Dec. 31, 2004. This increase is attributable to a decrease in the current portion of long-term debt of $300.0 million representing the portion of the preferred securities which were redeemed in February 2005. TransAlta expects to have sufficient sources of internal and external capital to finance operations and growth in the short and long term.

In 2006, cash will be provided by a combination of cash flow from operations and utilization of various credit facilities. Cash requirements include planned maintenance, additions to capital assets, dividend payments and repayment of short-term and maturing senior debt. Cash provided by operations in 2005 was $619.4 million and at Dec. 31, 2005, there were approximately $1.2 billion available under credit facilities. In 2006, capital expenditures are expected to be $260.0 million to $275.0 million and $396.4 million of existing debt is scheduled to be repaid in 2006.

Long-term funding is provided through the maintenance of investment grade credit ratings and a carefully managed capital structure, which together create a strong balance sheet and ready access to capital markets at competitive rates. Our objective is to manage the maturities of the various securities on issue such that no more than 15 per cent of the total outstanding securities mature in any one year. Our target is to maintain a capital structure and coverage ratios consistent with investment grade credit ratings. Our capital structure consisted of the following components at Dec. 31, 2005, 2004 and 2003:

	2005		2004		2003	
			(Restated, Note 1)		*(Restated, Note 1)*	
Debt, net of cash and interest-earning investments	**$ 2,538.8**	**43%**	$ 2,534.4	42%	$ 2,964.4	47%
Preferred securities	**175.0**	**3%**	475.0	8%	475.0	7%
Other non-controlling interests	**558.6**	**10%**	616.4	10%	477.9	8%
Common shareholders' equity	**2,543.1**	**44%**	2,470.0	40%	2,450.5	38%
	$ 5,815.5	**100%**	$ 6,095.8	100%	$ 6,367.8	100%

At Dec. 31, 2005, our total debt (including non-recourse debt) to invested capital ratio was 43.6 per cent (39.8 per cent excluding non-recourse debts) compared to the Dec. 31, 2004 ratio of 46.4 per cent and the Dec. 31, 2003 ratio of 46.2 per cent.

Additional key financial ratios were as follows:

	2005	2004	2003
		(Restated, Note 1)	*(Restated, Note 1)*
Cash flow to interest[1]	**4.8**	4.3	3.4
Cash flow to total debt[2]	**23.5%**	19.1%	17.1%

1 *Cash flow from operations before changes in working capital plus net interest expense divided by interest on recourse and non-recourse debt less interest income.*

2 *Cash flow from operations before changes in working capital divided by two-year average of total debt.*

Contractual repayments of long-term debt, commitments under operating leases, fixed price purchase contracts and commitments under mining agreements are as follows:

	2006	2007	2008	2009	2010	2011 and thereafter	Total
Long-term debt[1]	$ 396.4	$ 249.4	$ 157.6	$ 239.7	$ 29.4	$ 1,707.5	$ 2,780.0
Operating leases	12.8	11.3	10.3	9.6	9.3	86.6	139.9
Fixed price purchase contracts	55.8	56.5	58.3	35.2	13.4	127.0	346.2
Mining agreements	61.6	44.9	34.1	20.1	19.9	297.7	478.3
Total contractual cash obligations	$ 526.6	$ 362.1	$ 260.3	$ 304.6	$ 72.0	$ 2,218.8	$ 3,744.4

1 Includes capital lease obligations.

In addition, we have entered into a number of long-term power sales, gas purchase and transportation agreements in the normal course of operations as hedges of our operations.

In the normal course of operations, TransAlta and certain of our subsidiaries enter into agreements to provide financial or performance assurances to third parties. This includes guarantees, letters of credit and surety bonds which are entered into to support or enhance creditworthiness in order to facilitate the extension of sufficient credit for Energy Marketing trading activities, treasury hedging, Generation construction projects, equipment purchases and mine reclamation obligations.

At Dec. 31, 2005, the corporation had letters of credit outstanding of $216.9 million and US$415.3 million. The letters of credit were issued to counterparties that have credit exposure to the corporation or certain subsidiaries. If the corporation or a subsidiary does not meet the obligations under the contract, the counterparty may present its claim for payment to the financial institution, which in turn will request payment from the corporation. The letters of credit are generally issued under the corporation's committed $1.5 billion credit facility and any amounts payable by the corporation upon presentation of a letter of credit by a counter party are repayable under the terms of the credit facility in May 2008.

The corporation has arranged for the issuance of a surety bond in the amount of US$192.0 million in support of future mine reclamation obligations at the Centralia mine. The surety bond is issued for the full period of time necessary to complete the required reclamation and is non cancelable. In the event that the corporation does not complete the reclamation obligations in accordance with regulations then the company that issued the surety bond will complete the necessary reclamation obligations and seek recovery of the costs from the corporation. The surety bond is secured by a letter of credit for US$96.0 million and a corporate indemnity. A provision for retirement obligations is included in deferred credits and other long-term liabilities (*Note 11* to the consolidated financial statements).

We have provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions in various derivatives. To the extent liabilities related to these guaranteed contracts exist for trading activities, they are included in the consolidated balance sheet. To the extent liabilities exist related to these guaranteed contracts for hedges, they are not recognized on the consolidated balance sheet. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at Dec. 31, 2005 totaled $1.83 billion. In addition, the corporation has a number of unlimited guarantees. The fair value of the trading and hedging positions under contracts where TransAlta has a net liability at Dec. 31, 2005, under the limited and unlimited guarantees, was $559.6 million as compared to $345.2 million at Dec. 31, 2004.

TransAlta has also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at Dec. 31, 2005 was $645.3 million, as compared to $662.5 million at Dec. 31, 2004. To the extent actual obligations exist under the performance guarantees at Dec. 31, 2005, they are included in accounts payable and accrued liabilities.

The corporation has approximately $1.2 billion of undrawn collateral available to secure these exposures.

During construction and until certain conditions were met, the corporation provided a guarantee to the lenders of the Campeche plant. On April 5, 2004 the guarantee was released and the US$133.6 million of debt related to the plant became non-recourse to the corporation.

At Feb. 16, 2005, the credit ratings for the corporation's various securities as determined by S&P, DBRS and Moody's Rating Services (Moody's) were as follows:

Credit Ratings	S&P	DBRS	Moody's
TransAlta Corporation			
Issuer rating	BBB		Baa2
Commercial paper		R-2 (high)	
Secured commercial paper		R-1 (low)	
Senior unsecured debentures	BBB	BBB	Baa2
Preferred securities/stock	BB+	Pfd-3y	
TransAlta Utilities Corporation			
Issuer rating	BBB		
Secured debt	BBB+	A (low)	

In November 2005, DBRS confirmed TransAlta's credit ratings of R-2 (high), BBB and Pfd-3y to the corporation's commercial paper, senior unsecured debentures and preferred securities, respectively; and revised the trend from negative to stable. In November 2005, DBRS assigned a rating of R-1 (low) to TransAlta's secured commercial paper program. In July 2004, Moody's confirmed TransAlta's credit rating of Baa2 with a negative outlook. In February 2006, S&P upgraded TransAlta's credit rating to BBB from BBB- and to BB+ from BB on the corporation's unsecured debentures and preferred securities, respectively.

On Feb. 16, 2006, we had approximately 199.5 million common shares outstanding, plus outstanding employee stock options to purchase 2.9 million shares.

OFF-BALANCE SHEET ARRANGEMENTS

Disclosure is required of all off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We have no such off-balance sheet arrangements.

Under Canadian GAAP, most derivatives used in hedging relationships are not recorded on the balance sheet *(Note 1(O))* to the consolidated financial statements.) Gains or losses during the term of the hedge are deferred and recognized in earnings in the same period and financial statement caption as the hedged exposure (settlement accounting). The fair values of these derivatives are disclosed in *Note 18* to the consolidated financial statements. We also enter into long-term electricity purchase and sale, gas purchase and transportation agreements in the normal course of operations. These contracts are not recorded on the balance sheet under Canadian GAAP. Under U.S. GAAP, some of these contracts meet the definition of a derivative, and would require mark-to-market accounting, but are eligible for the normal purchase and sale exemption under FASB Statement 133. This exemption is available as electricity cannot be stored in significant quantities and due to the requirement for electricity generators to maintain sufficient capacity to meet customers' demands, and is also available for physically settled commodity contracts if certain criteria are met.

Information regarding guarantees has been disclosed in the Liquidity and Capital Resources section.

As discussed in the New Accounting Standards section of this MD&A we no longer consolidate our Mexican plants, Campeche and Chihuahua. As a result, $133.2 million (2004 – $149.1 million) in non-recourse debt related to the Campeche plant is not included in long-term debt in our consolidated balance sheets.

RELATED PARTY TRANSACTIONS

On March 8, 2005, TA Cogen entered into an agreement with TEC whereby TEC provided a financial fixed-for-floating price swap to TA Cogen during planned maintenance at Sheerness in the second quarter of 2005.

As previously discussed in Significant Events, on Dec. 1, 2004, we completed the sale of our 50 per cent interest in the 220 MW Meridian Cogeneration Facility located in Lloydminster, Saskatchewan, to TA Cogen for fair value of $110.0 million. TA Cogen financed the acquisition through the use of $50.0 million of cash on hand and by the issuance of $30.0 million of units to each of TA Power and TEC. TA Cogen also issued an advance to TEC for $30.0 million. We recorded a gain of $11.5 million after-tax or $0.06 per common share.

On July 31, 2003, we completed the sale of our 50 per cent interest in the two-unit, 756 MW coal-fired Sheerness Generating Station to TA Cogen for $630.0 million. The exchange amount was at fair value and was determined based on an estimate of the future net cash flows of the plant and approved by the independent directors of TA Cogen. There are no ongoing

contractual commitments or arrangements resulting from this sale apart from the provision of operational and management services under normal commercial terms for the Sheerness plant.

The obligation to purchase all of TA Power's interest in TA Cogen on Dec. 31, 2018 (resulting from the 1998 sale of an interest in three Ontario cogeneration plants held by TA Cogen to TA Power) was removed as part of the Sheerness transaction. Accordingly, the unamortized portion of the 1998 deferred gain was recognized in 2003. In addition, the management agreements between TransAlta, TA Power and TA Cogen were amended to remove the mechanism for the deferral of management fees and remove the obligation for TA Power and TA Cogen to pay management fees to TransAlta in the future. As consideration for the amendments, TransAlta received $1.0 million from TA Power and $5.0 million from TA Cogen.

In February 2003, we entered into an agreement with CE Gen whereby we purchase available power from certain CE Gen subsidiaries under normal commercial terms. In addition, CE Gen has entered into contracts with related parties to provide administrative and maintenance services.

For the period November 2002 to November 2007, TA Cogen entered into a transportation swap transaction with a wholly-owned subsidiary of TransAlta, TEC. TEC operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. The business purpose of the transportation swap was to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for two of its plants over the period of the swap. This stabilizes cash distributions in TA Cogen and thereby preserves the value of the limited partnership as a financing vehicle of TransAlta. The notional gas volume in the transaction was the total delivered fuel for both facilities. Exchange amounts are based on the market value of the contract. TransAlta entered into an offsetting contract with an external third party, therefore we have no risk other than counterparty risk.

TA Cogen entered into a fixed-for-floating gas swap transaction with TEC for a 61-month period starting Dec. 1, 2000. The swap transaction provides TA Cogen with fixed price gas for both the Mississauga and Ottawa plants over the period. The floating prices associated with the Mississauga and Ottawa cogen plants' long-term fuel supply agreements were transferred to TEC's account. The notional gas volume in the transaction was the total delivered fuel for both facilities. As consideration and in negotiation, TA Cogen transferred the right to incremental revenues associated with curtailed electrical production and subsequent higher revenue gas sales. At Dec. 31, 2005, the portion of the contract related to the non-controlling interest had a fair value liability of $1.6 million (2004 – $4.9 million).

EMPLOYEE SHARE OWNERSHIP

We employ a variety of stock-based compensation plans to align employee and corporate objectives. At Dec. 31, 2005, 2.9 million options to purchase our common shares were outstanding, with 1.6 million exercisable at the reporting date. At Dec. 31, 2004, 2.9 million options to purchase our common shares were outstanding, with 2.0 million exercisable at the reporting date.

Under the terms of the Performance Share Ownership Plan (PSOP), certain employees receive awards which, after three years, make them eligible to receive a set number of common shares or cash equivalent plus dividends thereon based upon the performance of the corporation relative to companies comprising the S&P/TSX composite index. After three years, once PSOP eligibility has been determined, 50 per cent of the common shares may be released to the participant, while the remaining 50 per cent will be held in trust for one additional year. At Dec. 31, 2005, there were 1.2 million PSOP awards outstanding.

Under the terms of the Employee Share Purchase Plan, we will extend an interest-free loan to our employees below executive level of up to 30 per cent of the employee's base salary for the purchase of common shares of the corporation from the open market. The loan is repaid over a three-year period by the employee through payroll deductions unless the shares are sold, at which point the loan becomes due on demand. At Dec. 31, 2005, 0.6 million shares had been purchased by employees under this program.

EMPLOYEE FUTURE BENEFITS

We have registered pension plans in Canada and the United States covering substantially all employees of the corporation, its domestic subsidiaries and specific named employees working internationally. These plans have defined benefit and defined contribution options and in Canada, there is a supplemental defined benefit plan for Canadian based defined contribution members whose annual earnings exceed the Canadian income tax limit. The defined benefit option of the registered pension plan ceased for new employees on June 30, 1998. The latest actuarial valuations of the registered and supplemental pension plans were as at Dec. 31, 2005.

We provide other health and dental benefits to the age of 65 for both disabled members (other post-employment benefits) and retired members (other post-retirement benefits). The latest actuarial valuation of these other plans was as at Dec.31, 2004.

The supplemental pension plan is an obligation of the corporation. We are not obligated to fund the supplemental plan but are obligated to pay benefits under the terms of the plan as they come due. We have posted a letter of credit in the amount of $41.8 million to secure the obligations under the supplemental plan.

RISK FACTORS AND RISK MANAGEMENT

TransAlta uses a multi-level risk management oversight structure to manage the corporation's various risk and energy trading exposures.

The Audit and Environment (A&E) Committee provides assistance to the Board of Directors in fulfilling its oversight responsibility relating to the integrity of the corporation's financial statements and the financial reporting process; the systems of internal accounting and financial controls; the internal audit function; the external auditors' qualifications, independence, performance and reports; and the legal and environmental compliance programs as established by management and the Board of Directors. The A&E Committee approves our Commodity Risk and Financial Exposure Management policies.

Our Exposure Management (EM) Committee is chaired by our Chief Financial Officer and is comprised of the Directors of Financial Operations for each business unit, the Executive Vice-President of Corporate Development and Marketing, Vice-President and Treasurer, Vice-President and Comptroller and the Director of Risk Management. The EM Committee is responsible to review, monitor and report on compliance with our approved financial and commodity risk exposure management policies.

The following addresses some, but not all, risk factors that could affect TransAlta's future results. A discussion of critical estimates made in the application of accounting policies is provided in the Critical Accounting Policies and Estimates section that follows.

Commodity Price Risk

We have exposure to movements in certain commodity prices, including the market price of electricity and fuels used to produce electricity in both our electricity generation and proprietary trading businesses.

Our Alberta coal-fired and hydroelectric facilities operate under the Alberta government mandated PPAs which, among other things, establish the price at which power will be supplied. In addition to the Alberta PPAs, we have entered into a variety of short- and long-term contracts to minimize our exposure to short-term fluctuations in electricity prices. In 2005, we had approximately 68 per cent of production under long-term contracts (2004 – 69 per cent) and 82 per cent (2004 – 83 per cent) of production was contracted for terms greater than one year. In the event of a planned or unplanned plant outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfill our supply obligations under these short- and long-term contracts. We actively seek to mitigate this exposure through continued and proper maintenance of our electricity generating plants, force majeure clauses negotiated in our contracts, trading activities and insurance.

We buy natural gas and some of our coal to supply the fuel needed to operate our facilities. We have exposure to increases in the cost of such fuels to the extent such increases are greater than the increases in the price we can obtain for the electricity we produce. A significant portion of the coal used in electricity generation is from coal reserves owned by TransAlta, thereby limiting our exposure to fluctuations in the market price of coal. In 2005, 67 per cent (2004 – 70 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2004 – 100 per cent) of our purchased coal costs were contractually fixed.

Higher input costs, such as diesel and tires, increased amounts of overburden being removed to access coal reserves and mining operations moving further away from the power plants are all contributing to increased mining costs. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations. At Centralia, high amounts of rainfall can cause localized flooding and reduced equipment utilization. Diesel price variations are minimized through the use of diesel hedges and seasonal variations in coal mining costs and production are stabilized through the application of standard costing.

Our fuel supply and fuel costs for our gas-fired plants are managed with short-, medium- and long-term gas supply contracts, hedging transactions and contractual agreements that provide for the flow-through of gas costs. We believe adequate supplies of natural gas at reasonable prices will be available for plants when existing supply contracts expire.

Production and gross margins from our merchant gas plants are subject to changes in spark spreads. We have not entered into fixed commodity agreements for gas for these merchant plants as gas will be purchased concurrent with spot market spark spreads being adequate to produce and sell electricity.

Our proprietary trading of gas and electricity is limited, strictly controlled and managed through the use of VAR methodologies.

VAR is the most commonly used metric employed to track the risk of trading positions. A VAR measure gives, for a specific confidence level, an estimated maximum loss over a specified period of time.

VAR is the primary measure used to manage Energy Marketing's exposure to market risk resulting from trading activities. VAR is monitored on a daily basis, and is used to determine the potential change in the value of the corporation's marketing portfolio over a three-day period within a 95 per cent confidence level resulting from normal market fluctuations. Stress tests are performed weekly on both earnings and VAR to measure the potential effects of various market events that could impact financial results, including fluctuations in market prices, volatilities of those prices and the relationships between those prices.

We estimate VAR using the historical variance/covariance approach. Currently, there is no uniform energy industry methodology for estimating VAR. An inherent limitation of historical variance/covariance VAR is that historical information used in the estimate may not be indicative of future market risk.

Another method of looking at VAR is based on a 95 per cent confidence interval over a three-day holding period. For comparison purposes, the following table provides this average daily VAR of the corporation's marketing portfolio for 2005 and 2004:

	2005	2004
3-day average VAR – 95% confidence level	$ 3.6	$ 3.8

Currency Rate Exposure

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations and the acquisition of equipment and services from foreign suppliers. We have exposures primarily to the U.S., Mexican and Australian currencies. We limit our exposure to movements in these currencies in two ways. We hedge our net investments in foreign operations using a combination of foreign-denominated debt and financial instruments. The earnings from our foreign operations are substantially offset by expenditures denominated in the foreign currencies.

At Dec. 31, 2005, we have hedged approximately 96.8 per cent (2004 – 98.7 per cent) of our foreign currency translation exposure. Our strategy is to offset 90-100 per cent of all foreign currency exposures.

Translation gains and losses related to the carrying value of our foreign operations are deferred and included in the cumulative translation account in shareholders' equity. At Dec. 31, 2005, the balance in this account was a $67.0 million loss compared to a $52.2 million loss at the end of 2004.

Credit Risk

If the counterparties to our contracts are unable to meet their obligations, our revenues could be adversely affected. We actively manage our exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts. We set strict credit limits for each counterparty and the mix of counterparties based on their credit ratings. Counterparty exposures for trading activities are monitored daily. If the limits are exceeded, we take steps to reduce additional credit exposure by requesting collateral, if applicable, or by halting trading activity. However, there can be no assurances that we will be successful in identifying creditworthy counterparties or monitoring trading activities.

We are exposed to minimal credit risk for Alberta PPAs because under the terms of these arrangements all receivables are secured by letters of credit.

A summary of our credit risk exposure for trading operations at Dec. 31, 2005, including asset-backed trading, is provided below:

Rating	Exposure before credit collateral	Credit collateral	Net exposure	Number of counterparties greater than 10%	Net exposure of counterparties greater than 10%
Investment grade	$ 126.7	$ 0.9	$ 125.8	2	$ 51.8
Non-investment grade	–	–	–	–	–
No external rating, internally rated – investment grade	44.7	–	44.7	1	28.9
No external rating, internally rated – non-investment grade	2.3	–	2.3	–	–
	$ 173.7	$ 0.9	$ 172.8	3	$ 80.7

The maximum credit exposure to any one customer, excluding the California Independent System Operator and California Power Exchange Corp. discussed earlier in the Energy Marketing Segment and including the fair value of open trading positions, is $34.2 million receivable.

Liquidity Risk

We are exposed to liquidity risk under certain electricity and natural gas purchase and sale contracts entered into for the purposes of asset-backed sales and proprietary trading. Liquidity risk relates to our commitments to meet margin and collateral requirements under these contracts. The terms and conditions of these contracts may require us to provide collateral when the fair value of these contracts is both negative (out-of-the-money) and in excess of any credit limits granted by our counterparties. The fair value of these contracts changes due to changes in commodity prices and foreign exchange rates. These contracts are out-of-the-money in these circumstances: (i) for purchase agreements, when forward commodity prices are less than contracted prices; and (ii) for sales agreements, when forward commodity prices exceed contracted prices. Downgrades in our creditworthiness may decrease the credit limits granted by our counterparties.

In the absence of any credit limits granted by our counterparties, TransAlta's maximum collateral requirements would have been $559.6 million at Dec. 31, 2005. Collateral available was approximately $1.2 billion.

Interest Rate Exposure

Changes in interest rates can impact our borrowing costs and the capacity revenues we receive from our PPA plants. While these two streams represent a natural hedge against movements in interest rates, we also address this risk by employing a combination of fixed and floating rate debt instruments. Carrying a portion of our debt that is exposed to floating interest rates also allows us to take advantage of changes in the market. At Dec. 31, 2005, approximately 28.9 per cent (2004 – 23.9 per cent) of the corporation's total debt portfolio was subject to movements in floating interest rates through a combination of floating rate debt and interest rate swaps.

Hydro Risk

Our hydro operations financial performance is partially dependent upon the availability of water in a given year. The availability of water is difficult to forecast as it is primarily driven by weather and volume, timing and location of precipitation throughout the province of Alberta. Such water availability introduces a degree of volatility in revenues earned by our hydro operations from year to year. This risk is complicated by obligations imposed within the PPA applicable to the corporation's hydro plants. A monthly financial obligation must be paid to the PPA buyer, based on a predetermined quantity of energy and ancillary services at market prices, regardless of our ability to generate such quantities. We manage these risks on a real-time basis by monitoring water resources throughout Alberta to the best of our ability and optimizing this resource against real-time electricity market opportunities. We also play an important role in the management of water flows and levels in several key areas of Alberta, including two major cities. We carefully balance all of these factors together to achieve optimal productivity with the water resources available.

Operational Risk

Our plants are exposed to operational risks such as fatigue cracks in boilers, corrosion in boiler tubing, turbine failures and other issues that can lead to outages. A comprehensive plant maintenance program and regular turnarounds reduce this exposure. If the plants do not meet the availability or production targets specified in the PPAs or other long-term contracts, then we must either compensate the purchaser for the loss in the availability of production or suffer a reduction in electrical or capacity payments. Consequently, an extended outage could have a material adverse effect on our business, financial condition, results of operations or our cash flows. Insurance and force majeure clauses in the PPAs and other long-term contracts further mitigate this exposure.

The construction and development of generating facilities and acquisition activities are subject to various environmental, engineering and construction risks relating to cost-overruns, delays and performance. We attempt to minimize these risks by performing detailed analysis of project economics prior to construction or acquisition and by securing favourable power sales agreements.

The mines require permits from various governmental authorities to allow continued operation as well as commencement of operations in undeveloped areas. These permits are subject to change in various circumstances and there can be no guarantee that we will be able to obtain or maintain all the permits that may be required to develop or operate the mines and related facilities economically. We endeavour to be in compliance with all permit requirements at all times.

In Alberta, we have control of or own the land required to access the existing coal reserves and do not anticipate any issues in permitting these reserves. The existing permitted reserves at Centralia are nearing end of life and we are in the process of developing new resources that will provide sufficient coal, at current production levels, for the next 17 years. We are working closely with the regulators to ensure development of the new resources proceeds on schedule.

Of the corporation's labour force, 58 per cent is covered under 12 collective bargaining agreements. Two agreements were renegotiated in 2005 and we anticipate the renewal of four agreements in 2006. We do not anticipate any significant issues in the renegotiations of these agreements.

Environmental, Health and Safety Risk

TransAlta's approach to managing its environmental, health and safety (EHS) risk has three elements:

- Compliance-based activities, such as permitting and reporting,
- ISO-based EHS Management systems and programs, such as safety programs and auditing,
- Longer-term strategic initiatives, including climate change and government policy development.

These elements are integrated into our corporate-wide operations and management systems. They are designed to mitigate risks of our activities to employees, the public and the environment, and to address potential competitive risks from future changes in environmental policy. They are also supportive of our corporate commitment to sustainability.

We strive to maintain compliance with all environmental regulations relating to operations and facilities. Quarterly reports on all EHS regulatory changes are provided to each facility to ensure compliance is maintained. We produce and distribute quarterly and annual public reports on our performance. We seek continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts and environmental incidents.

We have implemented an ISO-based EHS management system designed to continuously improve environmental and safety performance. All of our plants have implemented the system, with one plant having an equivalent variation as required by our partner. Compliance with both regulatory requirements and management system standards is regularly audited through our Performance Assurance policy and results are reported quarterly to our Board of Directors.

TransAlta commits significant effort to work with regulators in Canada and the United States to ensure regulatory changes are well-designed and cost-effective. New emission reduction objectives for the power sector are being established by governments in Canada and the United States. We have compliance plans over the next decade for greenhouse gases, mercury, sulphur dioxide and oxides of nitrogen, which will be adjusted as regulations are finalized. Where capital investment for control equipment may be required, we have technology review processes underway.

Specifically on climate change, TransAlta has implemented a four-component strategy that manages future risk associated with climate change regulation and develops competitive business advantages. The cornerstones of the strategy are:

1. Internal operational improvements that lower the emissions of our generation operations. These include plant upgrades, intensive equipment maintenance, efficiency improvements and fuel decision choices.
2. Purchase of emission reduction offsets outside our operations. TransAlta has been a Canadian leader in this area and has created an offsets portfolio that will allow us to meet emission targets at competitive costs.
3. Renewable energy investments, particularly in the wind area, which reduce our emissions intensity and diversify our fuel mix.
4. Investments in clean coal technology development that provide long-term promise for large emission reductions from fossil-fired generation. TransAlta is a founder and active member of the Canadian Clean Power Coalition, an industry consortium developed to build Canada's first clean coal power plant.

We anticipate continued and growing scrutiny by investors relating to sustainability performance. Our reputation as a leader in this area is important, more so because in our opinion it represents both good management and competitive positioning. The Dow Jones Sustainability Index has again recognized TransAlta as one of the world's best utility companies in terms of sustainability performance. In 2005, we were also recognized as one of the world's top 100 sustainable companies in the Global 100 ranking of the World Economic Forum.

Mercury control requirements are being drafted in Canada and the United States and will impact coal-fired generation plants. In Alberta, TransAlta anticipates its coal-fired plants will require some form of mercury capture technology in the next five to seven years. The exact technology and performance requirements have not yet been finalized; however, TransAlta is maintaining engineering readiness. Our PPAs will also provide an opportunity to recover these costs under 'Change of Law' provisions. In the United States, TransAlta's Centralia coal-fired plant may or may not be subject to mercury reduction requirements by 2010, depending on Washington State determinations, which are expected by the end of 2006.

Regulatory and Political Risk

Certain of the markets in which the corporation operates are subject to significant regulatory oversight and control. The corporation is not able to predict whether there will be any changes in the regulatory environment or the ultimate effect of changes in the regulatory environment on its business. TransAlta manages these risks by working with governments, regulators and other stakeholders to attempt to resolve issues. In Ontario, new legislation was passed in December 2004 outlining a new electricity market structure. The new market design provides for a mix of: i) regulated assets, ii) unregulated assets and iii) government-backed long-term contracts. TA Cogen's assets have retained their existing government contracts in the restructured market. On Feb. 14, 2006, TransAlta signed a five-year contract with the Ontario Power Authority for its Sarnia cogeneration plant. Under the terms of the contract, the plant will be available to supply an average of 400 MW

of power to the Ontario electricity market. In Alberta, a wholesale market review task force and a retail market review were initiated in 2004 to evaluate the functioning of the electricity market and consider market design changes. A market design policy recommendation is expected in 2006. TransAlta continues to work with the task force to ensure any regulatory changes are well-designed and cost-effective. If regulations were to change however, the operational and financial impact on all Alberta plants and trading operations would need to be assessed. Outcomes may include, but are not limited to: increased compliance, operating or capital costs; reduced operational flexibility; or reduced power prices and volatility.

International investments are subject to unique risks and uncertainties relating to the political, social and economic structures of the respective country and such country's regulatory regime. The corporation may mitigate this risk through the use of non-recourse financing and political risk insurance.

Transmission Risks

In August 2003, a blackout cut off electricity to millions of residents in the Northeastern United States and Eastern Canada. This type of event, although extremely unusual, is an ongoing risk for electric companies. This risk is mitigated through force majeure clauses in the Alberta PPAs and power sales contracts and access to multiple transmission lines.

Corporate Structure

We conduct a significant amount of business through subsidiaries and partnerships. Our ability to meet and service debt obligations is dependent upon the results of operations of our subsidiaries and the payment of funds by such subsidiaries to the corporation in the form of distributions, loans, dividends or otherwise. In addition, TransAlta's subsidiaries may be subject to statutory or contractual restrictions which limit their ability to distribute cash to the ultimate shareholder, the corporation.

General Economic Conditions

Changes in general economic conditions impact product demand, revenue, operating costs, timing and extent of capital expenditures, the net recoverable value of PP&E, results of financing efforts, credit risk and counterparty risk.

Income Taxes

The corporation's operations are complex, and the computation of the provision for income taxes involves tax interpretations, regulations and legislation that are continually changing. The corporation's tax filings are subject to audit by taxation authorities. Management believes that it has adequately provided for income taxes based on all information currently available.

Legal Contingencies

The corporation is occasionally named as a defendant in various claims and legal actions. Exposure to these claims is mitigated through levels of insurance coverage considered appropriate by management and active management of these claims. Except as disclosed in *Note 22* to the consolidated financial statements, the corporation does not expect the outcome of the claims or potential claims to have a materially adverse effect on the corporation as a whole.

Other Contingencies

The corporation maintains a level of insurance coverage deemed appropriate by management. There were no significant changes to TransAlta's insurance coverage during 2005. The corporation's insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that insurance proceeds received by the corporation for any loss or damage will be sufficient.

Sensitivity Analysis

The following table shows the effect on net earnings and cash flows of changes in certain key variables. The analysis is based on business conditions and production volumes in 2005. Each separate item in the sensitivity assumes the others are held constant. While these sensitivities are applicable to the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances, or for greater magnitude of changes.

		Approximate impact	
Factor	Change	Cash flow	Earnings (after-tax)
Electricity price	$1.00/MWh increase	$ 10.8	$ 10.8
Natural gas price	$0.1/GJ increase	(1.1)	(1.1)
Availability/production	1% increase	13.8	13.8
Exchange rate (US$ per Cdn$)	US$0.01 decrease	(0.2)	(0.2)
Interest rate	1% increase	(10.7)	(7.0)
Tax rate	1% increase	(2.3)	(2.3)

The impact of a $1.00 per MWh change in electricity prices has minimal impact on our cash flow and after-tax earnings, as approximately 82 per cent of output is at contractually fixed prices. A change in natural gas prices also has minimal impact as the majority of gas costs have been contractually fixed or flow through to customers under terms of agreements.

The calculation of the impact of a one per cent change in availability assumes that production levels will change by an equivalent amount at the contracted plants. An increase in availability at the merchant gas plants would not result in increased production.

Our hedging strategies have minimized the impact of changes in exchange rates and interest rates as our net investments in foreign operations have been hedged and interest rates on 71.1 per cent of our debt have been fixed.

The income tax rate can change depending on the mix of earnings from various countries. Increased operating income will incur income tax expense at a rate of approximately 35 per cent compared to the forecasted overall rate of approximately 25 per cent.

NEW ACCOUNTING STANDARDS

Effective Jan. 1, 2005, we adopted the Canadian Institute of Chartered Accountants (CICA) Accounting Guideline 15 "Consolidation of Variable Interest Entities". The guideline establishes that a VIE is to be consolidated based upon the determination of who will receive the majority of a VIE's expected losses, expected residual returns, or both, defined as a variable interest, rather than solely based on the voting interests. Variable interests are ownership interests or contractual relationships that enable the holder to share in the financial risks and rewards resulting from the activities of a VIE.

The accounting guideline specifies that an entity is a VIE if either of the following criteria are met:

1. total equity invested is insufficient to finance the entity without additional subordinated financial support; or
2. the equity investment does not provide the shareholders the right to make decisions or absorb the risks and returns of the entity.

We have considered the provisions of the guideline for all subsidiaries and their related power purchase, power sale or tolling agreements. Factors we considered in this analysis include the duration of the agreements, how capacity and energy payments are determined, source of payment terms for fuel, as well as responsibility and payment for operating and maintenance expenses.

As a result of this review, we determined that our wholly-owned subsidiaries that hold our interests in the Campeche and Chihuahua power plants are each considered VIEs. We have determined that the nature of the fuel purchase and power sale contract relating to the wholly-owned Mexican operation insulates us from significant variability in the cash flows relating to the assets. Therefore, we are not the primary beneficiary of the VIE and do not consolidate these wholly-owned subsidiaries. Accordingly, the subsidiaries owning the Campeche and Chihuahua plants are presented as equity investments rather than as consolidated subsidiaries in our consolidated financial statements. All results from operations of the plant are presented as equity income in our consolidated income statement. There was no impact to net earnings as a result of adoption of this interpretation. We have restated prior periods to reflect this change in accounting standard.

The following is summary information about the subsidiaries holding our Campeche and Chihuahua plants:

Dec. 31	2005		2004	
	Campeche	Chihuahua	Campeche	Chihuahua
Total assets	$ 276.9	$ 302.6	$ 280.1	$ 318.3
Total liabilities	184.1	7.2	187.7	8.4
Maximum exposure to loss	93.7	307.9	89.7	328.6
Capacity (MW)	252	259	252	259
Annual production (GWh)	1,683	1,067	1,742	1,422

In March 2004, the U.S. Financial Accounting Standards Board (FASB) Emerging Issues Task Force (EITF) reached a consensus on EITF Issue No. 04-02, *Whether Mineral Rights are Tangible or Intangible Assets*, that mineral rights, as defined in the Issue, are tangible assets. As a result of this decision, we account for coal rights under both Canadian and U.S. GAAP as tangible assets. Prior period amounts have been reclassified from intangible assets to tangible assets (Dec. 31, 2003 – $58.5 million). There was no effect on our net earnings as a result of the reclassification.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules have changed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment relative to the circumstances existing in the business. Every effort is made to comply with all applicable rules on or before the effective date, and we believe the proper implementation and consistent application of accounting rules is critical. However, not all situations are specifically addressed in the accounting literature. In these cases, our best judgment is used to adopt a policy for accounting for these situations. This is accomplished by analogizing to similar situations and the accounting guidelines governing them, considering foreign accounting standards and consulting with our independent auditors about the appropriate interpretation and application of these policies. Each of the critical accounting policies involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact the corporation's consolidated financial statements.

Our significant accounting policies are described in *Note 1* to the consolidated financial statements. The most critical of these policies are those related to revenue recognition, PP&E, goodwill, asset retirement obligations, income taxes and employee future benefits *(Notes 1(C), (F), (G), (I), (L) and (M), respectively)*. Each policy involves a number of estimates and assumptions to be made by our management about matters that are highly uncertain at the time the estimate is made. Different estimates, with respect to key variables we used for the calculations, or changes to estimates could potentially have a material impact on our financial position or results of operations. These critical accounting estimates are described below.

We have discussed the development and selection of these critical accounting estimates with our A&E Committee and our independent auditors. The A&E Committee has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A.

Tables are provided in the following discussion to reflect the sensitivities associated with changes in key assumptions used in the estimates. The tables reflect an increase or decrease in the percentage or other factor for each assumption. The inverse of each change is generally expected to have a similar opposite impact. Each separate item in the sensitivity assumes all other factors remain constant.

Revenue Recognition

The majority of our revenues are derived from the sale of physical power and from energy marketing and trading activities. Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for being available; energy payments for generation of electricity; availability incentives or penalties for exceeding or not meeting availability targets; excess energy payments for power generation above committed capacity; and ancillary services. Each is recognized upon output, delivery or satisfaction of specific targets, as specified by contractual terms. Revenues from non-contracted capacity are comprised of energy payments for each MWh produced at market prices, and are recognized upon delivery.

Trading activities use derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting. Derivatives, other than real-time physical contracts, are presented on a net basis in the statements of earnings. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented on the balance sheets as price risk management assets and liabilities. Non-derivative contracts are accounted for using the accrual method. To be consistent with the EITF 03-11, TransAlta has concluded that real-time physical contracts meet the definition of derivative contracts held for delivery and therefore realized gains and losses are reported gross in the statement of earnings.

The determination of the fair value of energy trading contracts and derivative instruments is complex and relies on judgments concerning future prices, volatility and liquidity, among other factors. The majority of derivatives traded by TransAlta have quoted market prices or over-the-counter quotes available from brokers. However, some derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available. These derivatives require the use of internal valuation techniques or models (mark-to-model accounting).

Mark-to-model accounting is currently used for physical and financial forward contracts and option contracts on transmission and transmission congestion. Accrual accounting is used for transmission rights acquired to sell production from our plants, and physical transmission rights used by the Energy Marketing segment. Changes in fair value of derivatives subsequent to inception are recorded on the balance sheet as price risk management assets or liabilities, with the offset recorded in revenues. The values can be favourable or unfavourable, and depending on current market conditions, values can fluctuate significantly, with the effect of changes being recorded through earnings in the period of the change. Modeling

techniques require the corporation to model future prices, price correlation, market volatility, liquidity and other forecasted market intelligence, as well as the use of mathematical extrapolation techniques. Where appropriate, the estimates used to derive fair value reflect the potential impact for uncertainties in the modeling process, the potential impact of liquidating the corporation's position in an orderly manner over a reasonable period of time under present market conditions and operational risk. We validate our mark-to-model results by comparing against settled data. The amounts reported in the financial statements may change as estimates are revised to reflect actual results or new information, changes in market conditions or other factors, many of which are beyond our control, and may be material.

Key variables used in the models are uncertain. The estimated value of these contracts at Dec. 31, 2005 using mark-to-model methodology was $3.9 million. Sensitivities of the valuation, which would have been recorded in earnings in the current year, are as follows:

Assumption	Change in assumption	Impact on pre-tax earnings
Change in volatility	1%	$ (0.5)
Change in commodity price	1%	3.6

There have been no significant changes to the modeling techniques in the past three years.

Valuation of PP&E

PP&E makes up 71.6 per cent of our assets, of which 99 per cent relates to the Generation segment. On an annual basis, and when indicators of impairment exist, we determine whether the net carrying amount of PP&E is recoverable from future undiscounted cash flows. Factors which could indicate that an impairment exists include significant underperformance relative to historical or projected operating results, significant changes in the manner or use of the assets, the strategy for the corporation's overall business and significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where we are not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

Our businesses, the markets and business environment are continually monitored, and judgments and assessments are made to determine whether an event has occurred that indicates possible impairment. If such an event has occurred, an estimate is made of the future undiscounted cash flows from the asset. If the total of the undiscounted future cash flows excluding financing charges, with the exception of plants that have specifically dedicated debt, is less than the carrying amount of the asset, an asset impairment charge must be recognized in our financial statements. The amount of the impairment recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties, and is best estimated by calculating the net present value of future expected cash flows related to the asset. Both the identification of events that may trigger an impairment and the estimates of future cash flows and the fair value of the asset require considerable judgment.

The assessment of asset impairment requires management to make significant assumptions about future sales prices, cost of sales, production and fuel consumed over the life of the plants (up to 30 years), retirement costs and discount rates. In addition, when impairment tests are performed, the estimated useful lives of the plants are reassessed, with any change accounted for prospectively.

In estimating future cash flows of the plants, we use estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, and transmission capacity or constraints for the remaining life of the plant. Actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

On an annual basis, or as events indicate, TransAlta performs an impairment review of its plants. As a result of this review, we have determined that the Ottawa plant was impaired in the accounts of TA Cogen. A fundamental shift in the gas markets and forecast increases in the cost of natural gas have lowered expected margins from the Ottawa plant as TA Cogen does not have a gas supply contract in place for the period 2008 – 2012 to match the contract to provide electricity under predetermined prices to the Ontario Electricity Financial Corporation (OEFC). Based upon the current view of gas costs and market conditions for that period and the likelihood that the plant will not operate as extensively beyond 2012, a reduction in the carrying value was required and a charge of $36.2 million was recognized in the fourth quarter of 2005. The discussion of Significant Events discloses our treatment of this item.

Had assumptions been made that resulted in future cash flows of the plants declining by 10 per cent, certain of TransAlta's plants would have been impaired at Dec. 31, 2005.

During 2003, our Binghamton plant did not run on a regular basis. This indicated that an impairment may have existed; therefore the plant was reviewed for impairment. The Binghamton plant sells electricity to the New York area at spot market rates when such prices exceed its marginal operating costs of producing electricity. We determined that undiscounted expected future cash flows from the Binghamton plant were less than the carrying value of the asset, therefore a pre-tax impairment charge of $5.6 million was recognized in the fourth quarter of 2003.

The fair value of the Binghamton plant was calculated from the expected present value of future cash flows. Management was required to make several estimates of future results and events. The range of pre-tax impairment charges resulting from management's estimates was from $3.1 million to $8.1 million.

In the second quarter of 2003, we determined that future growth would be slower than previously anticipated. This reduction in expansion plans, combined with an unsuccessful bid for the Valladolid project in Mexico, indicated that an impairment of our turbine inventory may exist. As a result, our turbine inventory was reviewed for impairment. We concluded that the carrying amount of our turbine inventory was not recoverable and the fair value of the turbines was less than the carrying value of the assets; therefore an $84.7 million asset impairment charge was recognized. Fair value was estimated using market prices for the same or similar turbines.

Asset Retirement Obligations

We recognize asset retirement obligations for PP&E in the period in which they are incurred if a reasonable estimate of a fair value can be determined. The fair value of the liability is described as the amount at which the liability could be settled in a current transaction between willing parties. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many asset retirement obligations. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of the entity's credit standing. Determining asset retirement obligations requires estimating the life of the related asset and the costs of activities such as demolition, dismantling, restoration and remedial work based on present day methods and technologies.

At Dec. 31, 2005, the asset retirement obligations recorded on the consolidated balance sheet were $249.2 million. We estimate the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $1.2 billion, which will be incurred between 2007 and 2072. The majority of the costs will be incurred between 2020 and 2030. A discount rate of eight per cent was used to calculate the carrying value of the asset retirement obligations.

Sensitivities for the major assumptions are as follows:

Assumption	Change in assumption	Impact on pre-tax earnings
Discount rate	1%	$ 2.5
Undiscounted asset retirement obligations	1%	0.2

Useful Life of PP&E

PP&E is depreciated over its estimated useful life. Estimated useful lives were determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand and the potential for technological obsolescence. Major components of plants are depreciated over their own useful lives. A component is a tangible asset that can be separately identified as an asset, and is expected to provide a benefit of greater than one year.

Depreciation and amortization expense was $400.9 million in 2005, of which $49.9 million relates to mining equipment, and is included in fuel and purchased power.

The rates used are reviewed on an ongoing basis to ensure they continue to be appropriate, and are also reviewed in conjunction with impairment testing, as discussed above.

A five per cent change in the estimated useful life of depreciable assets will result in a change of $17.6 million in depreciation and amortization expense.

Valuation of Goodwill

We evaluate goodwill for impairment at least annually, or more frequently if indicators of impairment exist. If the carrying value of a reporting unit including goodwill exceeds the reporting unit's fair value, any excess represents the impairment loss.

Goodwill was recorded on the acquisitions of Merchant Energy Group of the Americas (MEGA), Vision Quest Windelectric and CE Gen. At Dec. 31, 2005, this goodwill had a total carrying value of $137.6 million.

We reviewed the goodwill in the fourth quarter of 2005 in connection with our annual impairment tests. To test for impairment, the fair value of the reporting units to which the goodwill relates were compared to the carrying values of the reporting units. We determined that the fair values of our reporting units, based on historical cash flows and estimates of future cash flows, exceeded their carrying values; therefore, no impairment charges were recorded.

Determining the fair value of the reporting units is susceptible to changes from period to period as management is required to make assumptions about future cash flows, production and trading volumes, margins and fuel and operating costs. Had assumptions been made that resulted in fair values of the reporting units declining by 10 per cent from current levels, there would not have been any impairment of goodwill. To the extent goodwill was impaired, the impairment charge would impact earnings in the period of the charge.

Income Taxes

In accordance with Canadian GAAP, we use the liability method of accounting for future income taxes and provide future income taxes for all significant income tax temporary differences.

Preparation of the consolidated financial statements requires an estimate of income taxes in each of the jurisdictions in which we operate. The process involves an estimate of our actual current tax exposure and an assessment of temporary differences resulting from differing treatment of items, such as depreciation and amortization, for tax and accounting purposes. These differences result in future tax assets and liabilities, which are included in our consolidated balance sheet.

An assessment must also be made to determine the likelihood that our future tax assets will be recovered from future taxable income. To the extent that recovery is not considered likely, a valuation allowance must be determined. Judgment is required in determining the provision for income taxes, future income tax assets and liabilities and any related valuation allowance. To the extent a valuation allowance is created or revised, current period earnings will be affected.

Future tax assets of $173.7 million have been recorded on the consolidated balance sheet at Dec. 31, 2005. This is comprised primarily of unrealized losses on electricity trading contracts, asset retirement obligation costs and net operating and capital loss carryforwards. We believe there will be sufficient taxable income and capital gains that will permit the use of these deductions and carryforwards in the tax jurisdictions where they exist.

Future tax liabilities of $758.5 million have been recorded on the consolidated balance sheet at Dec. 31, 2005. The liability is comprised primarily of unrealized gains on electricity trading contracts and income tax deductions in excess of related depreciation of PP&E.

Judgment is required to assess tax interpretations, regulations and legislation, which are continually changing, to ensure liabilities are complete and to ensure assets, net of valuation allowances, are realizable. The impact of different interpretations and applications could potentially be material.

Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change the tax liability of the corporation, although we believe that we have adequately provided for income taxes based on all information currently available. The outcome of the audits is not known, nor is the potential impact on the financial statements determinable.

Employee Future Benefits

As explained in *Note 17* to the consolidated financial statements, we provide post-retirement benefits to employees. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The liability for future benefits and associated pension costs included in annual compensation expenses are impacted by employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans and earnings on plan assets. Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

The plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions:

Actuarial assumption	Change in assumption	Impact on projected benefit obligation	Impact on pension cost reported in earnings
Discount rate	1%	$ 47.7	$ 2.4
Rate of return on plan assets	1%	–	3.4

The discount rate used represents high-quality fixed income securities currently available and expected to be available during the period to maturity of the pension benefits. We do not expect to make any changes to the rate in 2006.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. For the year ended Dec. 31, 2005, the plan assets had a return of $43.9 million compared to a return of $33.4 million in 2004 and $35.9 million in 2003. The 2005 actuarial valuation used the same rate of return on plan assets (7.0 per cent) as was used in 2004 and 2003.

As a result of our plan asset return experience for the U.S. registered pension plan, at Dec. 31, 2005, the corporation was required under U.S. GAAP to recognize an additional minimum liability *(Note 25* to the consolidated financial statements). The liability was recorded as a reduction in common equity through a charge to other comprehensive income (OCI), and did not affect net income for 2005.

The amount of the additional pension liability recognized for U.S. GAAP depended on a number of factors, including the discount rate and asset returns experienced, contributions made by the corporation and any resulting change in management's assumptions. Pension cost and cash funding requirements could increase in future years.

NON-GAAP MEASURES

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below are not defined under GAAP and therefore should not be considered in isolation or as an alternative to, or more meaningful than, net income or cash flow from operations as determined in accordance with GAAP as an indicator of our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

Each business unit assumes responsibility for its operating results measured to operating income. Operating income is a measure of financial performance used by TransAlta's analysts and investors to analyze and compare companies on the basis of operating performance.

Gross margin less operating expenses and operating income provide us with a measurement of operating performance that is readily comparable from period to period.

Gross margin less operating expenses and operating income are reconciled to net earnings below:

Year ended Dec. 31	2005	2004	2003
		(Restated, Note 1)	*(Restated, Note 1)*
Gross margin	**$ 1,462.6**	$ 1,356.8	$ 1,325.3
Operating expenses	**(985.2)**	(925.5)	(893.5)
	477.4	431.3	431.8
Gain on sale of Sheerness Generating Station	**–**	–	191.5
Gain on sale of Meridian Cogeneration Facility	**–**	17.7	–
Gain on sale of TA Power partnership units	**–**	44.8	15.2
Gain on sale of land	**–**	–	10.5
Asset impairment charges	**(36.2)**	–	(90.3)
Prior period regulatory decision	**–**	(22.9)	–
Operating income	**441.2**	470.9	558.7
Other expense	**–**	–	(3.2)
Foreign exchange gain (loss)	**1.0**	0.7	(4.7)
Net interest expense	**(188.6)**	(207.4)	(212.1)
Equity loss	**(0.9)**	(8.5)	(6.0)
Earnings before non-controlling interests and income taxes	**252.7**	255.7	332.7
Non-controlling interests	**18.5**	46.0	34.2
Earnings before income taxes	**234.2**	209.7	298.5
Income tax expense	**47.4**	49.1	64.3
Earnings from continuing operations	**186.8**	160.6	234.2
Gain on disposal of discontinued operations, net of tax	**12.0**	9.6	–
Net earnings	**$ 198.8**	$ 170.2	$ 234.2

Presenting earnings on a comparable basis from period to period provides us with the ability to evaluate earnings trends more readily in comparison with prior periods' results. To do so the following items, which we believe would otherwise affect the comparability of our operating results from period to period, are excluded from net earnings: gains on sale of the Sheerness Generating Station, TA Power units, the Meridian Cogeneration Facility and land, asset impairment charges, prior period regulatory decisions, and earnings from discontinued operations, net of tax.

Earnings presented on a comparable basis from period to period is reconciled to net earnings below:

Year ended Dec. 31	2005	2004 (Restated, Note 1)	2003 (Restated, Note 1)
Earnings on a comparable basis	**$ 173.8**	$ 128.1	$ 128.7
Tax settlement on deferred receivable	**13.0**	–	–
Gain on sale of Sheerness Generating Station, net of tax	**–**	–	145.8
Gain on sale of Meridian Cogeneration facility, net of tax	**–**	11.5	–
Gain on sale of TA Power units, net of tax	**–**	29.1	10.1
Gain on sale of land, net of tax	**–**	–	8.6
Asset impairment charges, net of tax	**–**	–	(59.0)
Prior period regulatory decision, net of tax	**–**	(14.9)	–
New Zealand tax settlement	**–**	6.8	–
Gain from discontinued operations, net of tax	**12.0**	9.6	–
Net earnings	**$ 198.8**	$ 170.2	$ 234.2
Weighted average common shares outstanding in the period	**196.8**	192.7	185.3
Earnings on a comparable basis per share	**$ 0.88**	$ 0.66	$ 0.69

SELECTED QUARTERLY FINANCIAL INFORMATION

2005 Quarters	First	Second	Third	Fourth
Revenue	**$ 684.3**	**$ 621.2**	**$ 722.9**	**$ 810.1**
Earnings from continuing operations	**51.7**	**24.8**	**52.1**	**58.2**
Net earnings	**51.7**	**24.8**	**52.1**	**70.2**
Basic earnings per common share:				
Continuing operations	**0.27**	**0.13**	**0.27**	**0.29**
Net earnings	**0.27**	**0.13**	**0.27**	**0.35**
Diluted earnings per common share:				
Continuing operations	**0.26**	**0.13**	**0.27**	**0.29**
Net earnings	**0.26**	**0.13**	**0.27**	**0.35**

2004 Quarters *(Restated, Note 1)*	First	Second	Third	Fourth
Revenue	$ 655.0	$ 592.9	$ 678.2	$ 660.1
Earnings from continuing operations	47.2	15.5	35.8	62.1
Net earnings	47.2	25.1	35.8	62.1
Basic earnings per common share:				
Continuing operations	0.25	0.08	0.18	0.32
Net earnings	0.25	0.13	0.18	0.32
Diluted earnings per common share:				
Continuing operations	0.24	0.08	0.18	0.32
Net earnings	0.24	0.13	0.18	0.32

Our results are partly seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower as electricity prices generally increase in the winter months in the Canadian market. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring run-off and rainfall in the Canadian and U.S. markets. Our results reflect the completion, acquisition, and disposition of plants and facilities throughout 2003, 2004 and 2005 as described previously within this MD&A.

CERTIFICATION

TransAlta's President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer have filed with the Securities and Exchange Commission (SEC) certifications regarding the quality of TransAlta's public disclosures relating to its fiscal 2005 reports filed with the SEC.

As at Dec. 31, 2005, our Management, together with our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based upon this evaluation, our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer have concluded that our disclosure controls and procedures are effective.

There were no changes in our internal controls over financial reporting during the fiscal year that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements, including statements regarding the business and anticipated financial performance of TransAlta. In some cases, forward-looking statements can be identified by terms such as 'may', 'will', 'believe', 'expect', 'potential', 'enable', 'continue' or other comparable terminology. These statements are not guarantees of TransAlta's future performance and are subject to risks, uncertainties and other important factors that could cause the corporation's actual performance to be materially different from those projected. Some of the risks, uncertainties, and factors include, but are not limited to: legislative and regulatory developments that could affect revenues, costs, and the speed and degree of competition entering the market; global capital markets activity; timing and extent of changes in commodity prices, prevailing interest rates, currency exchange rates, inflation levels and general economic conditions in geographic areas where TransAlta operates; results of financing efforts; changes in counterparty risk; and the impact of accounting policies issued by Canadian and U.S. standard setters. Given these uncertainties, the reader should not place undue reliance on these forward-looking statements. See additional discussion under Risk Factors and Risk Management in this MD&A.

TransAlta measures capacity as net maximum capacity (see Glossary for definition of this and other key terms), which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated.

TransAlta's management is responsible for presentation and preparation of the annual consolidated financial statements, management's discussion and analysis (MD&A) and all other information in this annual report.

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and the requirements of the Securities and Exchange Commission (SEC) in the United States, as applicable.

The MD&A has been prepared in accordance with the requirements of securities regulators including National Instruments 44-101 and 51-102 of the Canadian Securities Administrators as well as Item 303 of Regulation S-K of the Securities Exchange Act, and their related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration for materiality. In addition, in preparing financial information, the corporation must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect reported information. The MD&A also includes information regarding the estimated impact of current transactions and events, sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from management's present assessment of this information because future events and circumstances may not occur as expected.

The financial information presented elsewhere in this annual report is consistent with that in the consolidated financial statements.

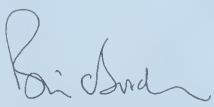
To meet its responsibility for reliable and accurate financial statements, management has established systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization. These systems are monitored by management and by internal auditors. In addition, the internal auditors perform appropriate tests and related audit procedures.

The consolidated financial statements have been examined by Ernst & Young LLP, independent chartered accountants. The external auditors' responsibility is to express a professional opinion on the fairness of management's consolidated financial statements. The auditors' report outlines the scope of their examination and sets forth their opinion.

The Audit and Environment (A&E) Committee of the Board of Directors is comprised of independent directors. The A&E Committee meets regularly with management, the internal auditors and the external auditors to satisfy itself that each is properly discharging its responsibilities, and to review the consolidated financial statements and MD&A. The A&E Committee reports its findings to the Board of Directors for consideration when approving the consolidated financial statements for issuance to the shareholders. The A&E Committee also recommends, for approval of shareholders, the appointment of the external auditors. The internal and external auditors have full and free access to the A&E Committee.

TransAlta's President and Chief Executive Officer, Executive Vice-President and Chief Financial Officer have certified TransAlta Corporation's annual disclosure documents in the United States as required by the U.S. Sarbanes-Oxley Act and in Canada by the Canadian securities regulators.

STEPHEN G. SNYDER
President & Chief Executive Officer
February 16, 2006



BRIAN BURDEN
Executive Vice-President & Chief Financial Officer

REPORT OF INDEPENDENT AUDITORS

To the Shareholders of TransAlta Corporation

We have audited the consolidated balance sheets of TransAlta Corporation as at December 31, 2005 and 2004 and the consolidated statements of earnings and retained earnings and cash flows for each of the years in the three year period ended December 31, 2005. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Corporation's internal control over financial reporting. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2005 in conformity with Canadian generally accepted accounting principles.

As discussed in *Note 1* to the consolidated financial statements, in 2005 the Corporation changed its method of accounting for variable interest entities.

Ernst & Young LLP

CHARTERED ACCOUNTANTS
Calgary, Canada
February 16, 2006

CONSOLIDATED STATEMENTS OF EARNINGS & RETAINED EARNINGS

Year ended Dec. 31 *(in millions of Canadian dollars except per share amounts)*	2005	2004 *(Restated, Note 1)*	2003 *(Restated, Note 1)*
Revenues	**$ 2,838.5**	$ 2,586.2	$ 2,413.5
Trading purchases	**(174.1)**	(197.7)	(97.4)
Fuel and purchased power	**(1,201.8)**	(1,031.7)	(990.8)
Gross margin	**1,462.6**	1,356.8	1,325.3
Operations, maintenance and administration	**596.0**	547.5	540.8
Depreciation and amortization *(Note 2)*	**367.9**	357.5	329.8
Taxes, other than income taxes	**21.3**	20.5	22.9
Operating expenses	**985.2**	925.5	893.5
Gain on sale of Sheerness Generating Station *(Note 4)*	**–**	–	(191.5)
Gain on sale of Meridian Cogeneration Facility *(Note 4)*	**–**	(17.7)	–
Gain on sale of TransAlta Power partnership units *(Note 4)*	**–**	(44.8)	(15.2)
Gain on sale of land *(Note 4)*	**–**	–	(10.5)
Asset impairment charges *(Note 6)*	**36.2**	–	90.3
Prior period regulatory decision *(Note 15)*	**–**	22.9	–
	36.2	(39.6)	(126.9)
Operating income	**441.2**	470.9	558.7
Other expense	**–**	–	(3.2)
Foreign exchange gain (loss)	**1.0**	0.7	(4.7)
Net interest expense *(Note 10)*	**(188.6)**	(207.4)	(212.1)
Equity loss *(Note 1)*	**(0.9)**	(8.5)	(6.0)
Earnings before non-controlling interests and income taxes	**252.7**	255.7	332.7
Non-controlling interests *(Note 12)*	**18.5**	46.0	34.2
Earnings before income taxes	**234.2**	209.7	298.5
Income tax expense *(Note 16)*	**47.4**	49.1	64.3
Earnings from continuing operations	**186.8**	160.6	234.2
Earnings from discontinued operations, net of tax *(Note 3)*	**12.0**	9.6	–
Net earnings	**198.8**	170.2	234.2
Common share dividends	**(196.9)**	(192.7)	(185.0)
Adjustment arising from normal course issuer bid *(Note 13)*	**–**	(1.1)	–
Retained earnings			
Opening balance	**910.3**	933.9	884.7
Closing balance	**$ 912.2**	$ 910.3	$ 933.9
Weighted average common shares outstanding in the year	**196.8**	192.7	185.3
Basic earnings per share *(Note 13)*			
Earnings from continuing operations	**$ 0.95**	$ 0.83	$ 1.26
Earnings from discontinued operations	**0.06**	0.05	–
Net earnings	**$ 1.01**	$ 0.88	$ 1.26
Diluted earnings per share *(Note 13)*			
Earnings from continuing operations	**$ 0.95**	$ 0.83	$ 1.26
Earnings from discontinued operations	**0.06**	0.05	–
Net earnings	**$ 1.01**	$ 0.88	$ 1.26

See accompanying notes.

CONSOLIDATED BALANCE SHEETS

Dec. 31 *(in millions of Canadian dollars)*	2005	2004* *(Restated, Note 1)*
ASSETS		
Current assets		
Cash and cash equivalents	$ 79.3	$ 101.2
Accounts receivable *(Note 20)*	593.4	422.5
Prepaid expenses	75.8	52.3
Price risk management assets *(Note 18)*	63.8	41.9
Future income tax assets *(Note 16)*	26.6	21.5
Income taxes receivable	48.8	60.1
Inventory	27.7	39.9
Current portion of other assets *(Note 8)*	10.9	301.0
	926.3	1,040.4
Restricted cash *(Note 4)*	6.3	8.9
Investments *(Note 5)*	414.3	421.3
Property, plant and equipment *(Note 6)*		
Cost	8,411.8	8,295.4
Accumulated depreciation	(2,866.3)	(2,592.8)
	5,545.5	5,702.6
Goodwill *(Note 4)*	137.6	142.2
Intangible assets *(Note 7)*	349.8	392.3
Future income tax assets *(Note 16)*	147.1	132.0
Price risk management assets *(Note 18)*	13.8	11.3
Other assets *(Note 8)*	200.0	199.7
Total assets	$ 7,740.7	$ 8,050.7
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term debt *(Note 9)*	$ 13.1	$ 34.4
Accounts payable and accrued liabilities	590.3	442.6
Price risk management liabilities *(Note 18)*	58.3	27.7
Income taxes payable	13.8	6.1
Future income tax liabilities *(Note 16)*	18.2	11.1
Dividends payable	50.5	19.3
Deferred credits and other current liabilities *(Note 11)*	0.4	241.5
Current portion of long-term debt – recourse *(Note 10)*	354.2	538.1
Current portion of long-term debt – non-recourse *(Note 10)*	42.2	42.0
	1,141.0	1,362.8
Long-term debt – recourse *(Note 10)*	1,887.0	1,939.8
Long-term debt – non-recourse *(Note 10)*	321.6	381.3
Preferred securities *(Note 10)*	175.0	175.0
Deferred credits and other long-term liabilities *(Note 11)*	365.5	391.5
Future income tax liabilities *(Note 16)*	740.3	703.9
Price risk management liabilities *(Note 18)*	8.6	10.0
Non-controlling interests *(Note 12)*	558.6	616.4
Common shareholders' equity		
Common shares *(Note 13)*	1,697.9	1,611.9
Retained earnings	912.2	910.3
Cumulative translation adjustment	(67.0)	(52.2)
	2,543.1	2,470.0
Total liabilities and shareholders' equity	$ 7,740.7	$ 8,050.7

Contingencies *(Notes 15 and 22)*
Commitments *(Note 21)*

See accompanying notes.
* *Derived from the audited Dec. 31, 2004 consolidated financial statements.*

On behalf of the Board:

Donna Kaufman. William D. Anderson

DONNA SOBLE KAUFMAN
Director

WILLIAM D. ANDERSON
Director

Year ended Dec. 31 *(in millions of Canadian dollars)*	2005	2004 *(Restated, Note 1)*	2003 *(Restated, Note 1)*
Operating activities			
Net earnings	$ 198.8	$ 170.2	$ 234.2
Depreciation and amortization *(Note 2)*	400.9	390.1	368.9
Prior period regulatory decision *(Note 15)*	–	22.9	–
Gain on sale of TransAlta Power partnership units *(Note 4)*	–	(44.8)	(15.2)
Non-controlling interests	18.5	46.0	34.2
Write-down of investments *(Note 5)*	–	–	6.2
Asset retirement obligation accretion *(Note 11)*	19.3	19.3	22.0
Future income taxes *(Note 16)*	5.6	17.8	27.4
Change in unrealized loss (gain) from energy marketing activities	4.9	(9.7)	(18.6)
Asset retirement obligation costs settled *(Note 11)*	(29.4)	(19.7)	(26.5)
Foreign exchange (gain) loss	(1.0)	(0.7)	4.7
Asset impairment charge	36.2	–	90.3
Gain on sale of assets	–	(24.7)	(202.0)
Equity loss	0.9	8.5	6.0
Other non-cash items	(3.0)	–	3.2
	651.7	575.2	534.8
Change in non-cash operating working capital balances	(32.3)	16.0	(60.5)
Cash flow from operating activities	619.4	591.2	474.3
Investing activities			
Long-term receivables	–	90.8	–
Additions to property, plant and equipment	(325.5)	(345.7)	(434.4)
Proceeds on sale of property, plant and equipment *(Note 4)*	1.6	43.2	226.7
Proceeds on sale of TransAlta Power partnership units *(Note 4)*	–	116.5	37.2
Equity Investment	(9.3)	(10.1)	(95.3)
Restricted cash *(Note 4)*	2.3	1.1	46.7
Acquisitions *(Note 4)*	–	–	(323.4)
Proceeds on sale of long-term investments *(Note 5)*	–	–	21.6
Realized foreign exchange gains on net investment hedges *(Note 18)*	89.8	47.8	194.1
Deferred charges and other	(1.0)	(1.0)	11.8
Cash flow used in investing activities	(242.1)	(57.4)	(315.0)
Financing activities			
Repayment of short-term debt	(23.6)	(85.4)	(170.2)
Repayment of long-term debt	(139.3)	(284.7)	(601.1)
Dividends on common shares	(99.2)	(135.4)	(158.3)
Issuance of long-term debt	200.0	2.7	544.6
Redemption of common shares	–	(2.3)	–
Net proceeds on issuance of common shares	19.6	3.4	265.0
Distributions to subsidiaries' non-controlling limited partner	(77.5)	(48.4)	(38.9)
Redemption of preferred securities	(300.0)	–	–
Deferred financing charges and other	–	(1.2)	(6.6)
Reduction in advance to TransAlta Power *(Note 4)*	23.7	2.0	–
Cash flow used in financing activities	(396.3)	(549.3)	(165.5)
Cash flow from operating, investing and financing activities	(19.0)	(15.5)	(6.2)
Effect of translation on foreign currency cash	(2.9)	(7.1)	(7.2)
Increase in cash and cash equivalents	(21.9)	(22.6)	(13.4)
Cash and cash equivalents, beginning of year	101.2	123.8	137.2
Cash and cash equivalents, end of year	$ 79.3	$ 101.2	$ 123.8
Cash taxes paid	$ 14.7	$ 4.6	$ 34.1
Cash interest paid	$ 183.7	$ 218.2	$ 215.4

See accompanying notes.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Consolidation

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP). The significant differences are described in *Note 25*.

The consolidated financial statements include the accounts of TransAlta Corporation (TransAlta or the corporation), all subsidiaries and the proportionate share of the accounts of joint ventures and jointly controlled corporations.

B. Use of Estimates and Measurement Uncertainty

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, currency exchange rates, inflation levels and commodity prices, changes in economic conditions and legislative and regulatory changes *(Notes 7, 17, 18 and 22)*.

C. Revenue Recognition

The majority of the corporation's revenues are derived from the sale of physical power and from energy marketing and trading activities. Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for being available, energy payments for generation of electricity, incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity and ancillary services. Each is recognized upon output, delivery, or satisfaction of specific targets, all as specified by contractual terms. Revenues from non-contracted capacity are comprised of energy payments for each megawatt hour (MWh) produced at market prices, and are recognized upon delivery.

Derivatives used in trading activities include physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn trading revenues and to gain market information. These derivatives are accounted for using the fair value method of accounting. Derivatives, other than real-time physical contracts, are presented on a net basis in the statements of earnings. Real-time physical contracts meet the definition of derivative contracts held for delivery and therefore realized gains and losses are reported gross in the consolidated statements of earnings. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented on the balance sheets as price risk management assets and liabilities. Non-derivative trading contracts are accounted for using the accrual method.

The majority of the corporation's derivatives have quoted market prices on active exchanges or over-the-counter quotes are available from brokers. However, some derivatives are not traded on an active exchange or the contracts extend beyond the time period for which market-based quotes are available, requiring the use of internal valuation techniques or models (mark-to-model accounting).

D. Discontinued Operations

The results of discontinued operations are presented net of tax on a one-line basis in the consolidated statements of earnings. Interest expense, direct corporate overheads and income taxes are allocated to discontinued operations. General corporate overheads are not allocated to discontinued operations.

E. Inventory

The corporation's inventory balance represents fuel which is valued at the lower of cost and market value, defined as net replacement value. Inventory cost is determined using moving average cost. The costing method used is direct costing which is determined as the sum of all applicable expenditures and charges directly or indirectly incurred in bringing an inventory item to its existing condition and location.

F. Property, Plant and Equipment

The corporation's investment in property, plant and equipment (PP&E) is stated at original cost at the time of construction, purchase or acquisition. Original cost includes items such as materials, labour, interest and other appropriately allocated costs. As costs are expended for new construction, the entire amount is capitalized as PP&E on the consolidated balance sheet and is subject to depreciation upon commencement of commercial operations. The cost of routine maintenance and repairs, such as inspections and corrosion removal, and the replacement of minor parts, are charged to expense as incurred. Certain expenditures relating to replacement of components incurred during major maintenance are capitalized and amortized over the estimated benefit period of such expenditures. A component is a tangible portion of the asset that can be separately identified as an asset and depreciated over its own expected useful life, and is expected to provide a benefit of greater than one year.

The estimate of the useful life of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand and the potential for technological obsolescence. The useful life is used to estimate the rate at which the PP&E is depreciated or amortized. These estimates are subject to revision in future periods based on new or additional information.

Depreciation and amortization is calculated using straight-line, declining balance and unit-of-production methods. Coal rights are amortized on a unit of production basis, based on the estimated mine reserves.

TransAlta capitalizes interest on capital invested in projects under construction. Upon commencement of commercial operations, capitalized interest, as a portion of the total cost of the plant, is amortized over the estimated useful life of the plant.

On an annual basis, and when indicators of impairment exist, TransAlta determines whether the net carrying amount of PP&E is recoverable from future undiscounted cash flows. Factors that could indicate an impairment exists include significant underperformance relative to historical or projected future operating results, significant changes in the manner or use of the assets, significant negative industry or economic trends or a change in the strategy for the corporation's overall business. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated where TransAlta is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The corporation's businesses, the markets and business environment are continually monitored, and judgments and assessments are made to determine whether an event has occurred that indicates possible impairment. If such an event has occurred, an estimate is made of future undiscounted cash flows from the PP&E. If the total of the undiscounted future cash flows, excluding financing charges with the exception of plants that have specifically dedicated debt, is less than the carrying amount of the PP&E, an asset impairment must be recognized in the financial statements. The amount of the impairment charge to be recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties, and is normally estimated by calculating the present value of expected future cash flows related to the asset.

G. Goodwill

Goodwill is the cost of an acquisition less the fair value of the net assets of an acquired business. Goodwill and certain intangibles are not subject to amortization, but are instead tested for impairment at least annually, or more frequently if an analysis of events and circumstances indicate that a possible impairment may arise earlier. These events could include a significant change in financial position of the reporting unit to which the goodwill relates or significant negative industry or economic trends. To test for impairment, the fair value of the reporting units to which the goodwill relates is compared to the carrying values of the reporting units. The corporation determined that the fair values of the reporting units, based on historical cash flows and estimates of future cash flows, exceeded their carrying values. There was no impairment of goodwill at Dec. 31, 2005 or 2004.

H. Intangible Assets

Intangible assets consist of power sale contracts, with rates higher than market rates at the date of acquisition, acquired in the purchase of CE Generation LLC (CE Gen), a jointly controlled enterprise *(Note 4)*. Sale contracts are valued at cost and are amortized on a straight-line basis over the remaining contract period, which ranges from seven to 30 years at the date of acquisition.

I. Asset Retirement Obligations

The corporation recognizes asset retirement obligations in the period in which they are incurred if a reasonable estimate of a fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The liability is accrued over the estimated time period until settlement of the obligation and the asset is depreciated over the estimated useful life of the asset. Reclamation costs for mining assets were recognized on a unit-of-production basis. No provision for future site restoration for gas generation plants had been recorded as the costs of restoration are expected to be offset by the salvage value of the related plant.

TransAlta recorded an asset retirement obligation for all generating facilities for which it is legally required to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. For the hydro facilities, the corporation is required to remove the generating equipment, but is not legally required to remove the structures. TransAlta has recognized legal obligations arising from government legislation, written agreements between entities and case law. The asset retirement liabilities are recognized when the asset retirement obligation is incurred. Asset retirement liabilities for coal mines are incurred over time, as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

J. Investments

Effective Jan. 1, 2005, TransAlta retroactively adopted the new Canadian Institute of Chartered Accountants (CICA) Accounting Guideline 15 "Consolidation of Variable Interest Entities". The wholly-owned subsidiaries that hold TransAlta's interests in the Campeche and Chihuahua power plants are considered VIEs and are shown as equity investments. Investments in shares of companies over which the corporation exercises significant influence are accounted for using the equity method. Other investments are carried at cost. If there is an other than temporary decline in the value of an investment, it is written down to net realizable value.

K. Other Assets

Deferred licence fees and deferred contract costs are amortized on a straight-line basis over the useful life of the related assets or long-term contracts.

Financing costs for the issuance of long-term debt and preferred securities are amortized to earnings on a straight-line basis over the term of the related issue.

Other costs capitalized on the balance sheet include project development costs, which include external, direct and incremental costs that are necessary for completion of a potential acquisition or construction project. Business development costs are included in operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable and that efforts will result in future value to the corporation, at which time the future costs are included in PP&E or investments. The appropriateness of the carrying value of these costs is evaluated each reporting period, and unrecoverable amounts of capitalized costs for projects no longer probable of occurring are charged to expense in the current period.

L. Income Taxes

The corporation uses the liability method of accounting for income taxes for its operations. Under the liability method, income taxes are recognized for the differences between financial statement carrying values and the respective income tax basis of assets and liabilities (temporary differences), and the carry forward of unused tax losses. Future income tax assets and liabilities are measured using income tax rates expected to apply in the years in which temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is included in earnings in the period the change is substantively enacted. Future income tax assets are evaluated annually and if realization is not considered 'more likely than not', a valuation allowance is provided.

M. Employee Future Benefits

The corporation accrues its obligations under employee benefit plans and the related costs, net of plan assets. The cost of pensions and other post-employment and post-retirement benefits earned by employees is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The defined benefit pension plans are based on an employee's final average earnings and years of service. Pension benefits will increase annually by two per cent. The expected return on plan assets is based on the historical returns earned by assets of similar risk and performance. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the balance sheet date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Past service costs from plan amendments are amortized on a straight-line basis over the estimated average remaining service period of employees active at the date of amendment (EARSL). If the cumulative net unamortized gain or loss exceeds 10 per cent of the accrued benefit obligations or the market value of the plan assets, whichever is greater, the amount in excess of this 10 per cent and threshold is amortized to earnings over EARSL. When the restructuring of a benefit plan gives rise to both a curtailment and settlement of obligations, the curtailment is accounted for prior to the settlement. Transition obligations and assets arising from the prospective adoption of new accounting standards are amortized over EARSL.

N. Foreign Currency Translation

The corporation's self-sustaining foreign operations are translated using the current rate method. Translation gains and losses are deferred and included in the cumulative translation adjustment (CTA) account in shareholders' equity. Foreign currency denominated monetary and non-monetary assets and liabilities are translated at exchange rates in effect on the balance sheet date.

Transactions denominated in foreign currencies are translated at the exchange rate on the transaction date. The resulting exchange gains and losses on these items are included in net earnings.

O. Derivatives and Financial Instruments

Derivatives used in trading activities are described in *Note 1(C)*.

Physical and financial swaps, forward sales contracts, futures contracts and options are used to hedge the corporation's exposure to fluctuations in electricity and natural gas prices related to output from the plants. Under Canadian GAAP, if hedging criteria are met (described below), gains and losses on these derivatives are recognized in earnings in the same period and financial statement caption as the hedged exposure (settlement accounting). The derivatives are not recorded on the balance sheet.

Cross-currency interest rate swaps, foreign currency forward contracts and foreign currency debts are used to hedge exposure to changes in the carrying values of the corporation's net investments in foreign operations as a result of changes in foreign exchange rates. Under Canadian GAAP, gains and losses on the principal component of the cross-currency interest rate swaps as well as gains and losses on the forward sales contracts and foreign currency long-term debt are deferred and included in CTA. The gains and losses on the principal component of the cross-currency interest rate swaps as well as the gains and losses on forward sales contracts are deferred and recorded in other assets *(Note 8)* or deferred credits and other long-term liabilities *(Note 11)* as appropriate.

Foreign currency forward contracts are used to hedge the foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies. Under Canadian GAAP, if hedge criteria are met, these derivatives are not recognized on the balance sheet. Upon settlement of the derivative, any gain or loss on the forward contracts is deferred and included in other assets *(Note 8)* or deferred credits and other long-term liabilities *(Note 11)*, and is included in the cost of the asset or liability when the asset is purchased and depreciated over the asset's estimated useful life (settlement accounting).

Interest rate swaps are used to manage the impact of fluctuating interest rates on existing debt. These instruments are not recognized on the balance sheet under Canadian GAAP. Interest rate swaps require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. If hedge criteria are met, interest expense on the debt is adjusted to include the payments made or received under the interest rate swaps (settlement accounting).

To be accounted for as a hedge under both Canadian and U.S. GAAP, a derivative must be designated and documented as a hedge, and must be effective at inception and on an ongoing basis. The documentation defines all relationships between hedging instruments and hedged items, as well as the corporation's risk management objective and strategy for undertaking various hedge transactions. The process includes linking derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or anticipated transactions. The corporation also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. Hedge effectiveness of cash flows is achieved if the derivatives' cash flows substantially offset the cash flows of the hedged item and the timing of the cash flows is similar. Hedge effectiveness of fair values is achieved if changes in the fair value of the derivative substantially offset changes in the fair value of the item hedged. If a hedge is determined to be ineffective, U.S. and Canadian GAAP require the ineffective portion to be recognized in earnings in the current period. If the above hedge criteria are not met, the derivative is accounted for on the balance sheet at fair value, with the initial fair value and subsequent changes in fair value recorded in earnings in the period of change.

If a derivative that has been accorded hedge accounting matures, expires, is sold, terminated or cancelled, and is not replaced as part of the corporation's hedging strategy, the termination gain or loss is deferred and recognized when the gain or loss on the item hedged is recognized. If a designated hedged item matures, expires, is sold, extinguished or terminated, or the hedged item is no longer probable of occurring, any previously deferred amounts associated with the hedging item are recognized in current earnings along with the corresponding gains or losses recognized on the hedged item. If a hedging relationship is terminated or ceases to be effective, hedge accounting is not applied to subsequent gains or losses. Any previously deferred amounts are carried forward and recognized in earnings in the same period as the hedged item.

P. Stock-based Compensation Plans

The corporation has three types of stock-based compensation plans comprised of two stock option-based plans, and a Performance Share Ownership Plan (PSOP), described in *Note 14*. Under the fair value method, compensation expense is measured at the grant date at fair value and recognized over the service period. Effective Jan. 1, 2003, the corporation elected to prospectively use the fair value method of accounting for stock-based compensation arrangements. In 2005, the corporation granted options to purchase 1.2 million common shares of the corporation to its employees at a weighted average exercise price of $17.80 per common share. *Note 14* provides pro forma measures of net earnings and earnings per share had compensation expense been recognized for awards granted prior to 2003 based on the estimated fair value of the options on the grant date in accordance with the fair value method of accounting for stock-based compensation.

Stock grants under PSOP are accrued in corporate operations, maintenance and administration (OM&A) expense as earned to the balance sheet date, based upon the percentile ranking of the total shareholder return of the corporation's common shares in comparison to the total shareholder returns of companies comprising the S&P/TSX composite index. Compensation expense under the phantom stock option plan is recognized in OM&A expense for the amount by which the quoted market price of TransAlta's shares exceed the option price, and adjusted for changes in each period for changes in the excess over the option price. If stock options or stock are repurchased from employees, the excess of the consideration paid over the carrying amount of the stock option or stock cancelled is charged to retained earnings.

Q. Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash and highly liquid investments with original maturities of three months or less.

R. Changes in Accounting Standards

Effective Jan. 1, 2005, TransAlta adopted the CICA Accounting Guideline 15 "Consolidation of Variable Interest Entities" (VIE). The guideline establishes that a VIE is to be consolidated by the primary beneficiary based upon the determination of who will receive the majority of a VIE's expected losses, expected residual returns, or both, rather than solely based on the voting interests. Variable interests are ownership interests or contractual relationships that enable the holder to share in the financial risks and rewards resulting from the activities of a VIE.

The accounting guideline specifies that an entity is a VIE if either of the following criteria are met:

1. total equity invested is insufficient to finance the entity without additional subordinated financial support; or
2. the holders of the equity investment, as a group,
   i) do not have the right to make decisions about an entity's activities that have a significant effect on the success of the entity; or
   ii) are protected either directly or indirectly from variability in cash flows from the entity; or
   iii) do not have the right to all of the residual returns of the entity.

The corporation has considered the provisions of the guideline for all subsidiaries and their related power purchase, power sale or tolling agreements. Factors considered in the analysis include the duration of the agreements, how capacity and energy payments are determined, source of payment terms for fuel, as well as responsibility and payment for operating and maintenance expenses.

As a result of this review, the corporation determined that the wholly-owned subsidiary that holds TransAlta's interest in the Campeche power plant is considered a VIE as the equity invested was not sufficient to finance the entity without additional subordinated financial support. The corporation then determined that the power sale contract with the Comisión Federal de Electricidad (CFE) insulates the corporation from significant variability in the fuel costs and related cash flows from the entity. Therefore, TransAlta is not the primary beneficiary of the VIE and does not consolidate the entity. Accordingly, the subsidiary owning the Campeche plant is presented as an equity investment and the results from operations are presented as equity income on the consolidated income statement. There was no impact to net earnings as a result of adoption of this accounting guideline.

As a result of this review, the corporation determined that the wholly-owned subsidiary that holds TransAlta's interest in the Chihuahua power plant is considered a VIE as the power sale contract with the CFE indirectly protects TransAlta from the variability in the fuel costs and related cash flows from the entity. Therefore the entity is a VIE and as TransAlta is not the primary beneficiary of the VIE, it does not consolidate the entity. Accordingly, the subsidiary owning the Chihuahua plant is presented as an equity investment and the results from operations of the plant are presented as equity income on the consolidated income statement. There was no impact to net earnings as a result of adoption of this interpretation.

The following is summary information about the subsidiaries holding the Campeche and Chihuahua plants:

Dec. 31	2005		2004	
	Campeche	Chihuahua	Campeche	Chihuahua
Total assets	**$ 276.9**	**$ 302.6**	$ 280.1	$ 318.3
Total liabilities	**$ 184.1**	**$ 7.2**	$ 187.7	$ 8.4
Maximum exposure to loss	**$ 93.7**	**$ 307.9**	$ 89.7	$ 328.6
Capacity (MW)	**252**	**259**	252	259
Annual production (GWh)	**1,683**	**1,067**	1,742	1,422

NOTE 2. SEGMENT DISCLOSURES

A. Description of Reportable Segments

The corporation has two reportable segments: Generation and Energy Marketing. TransAlta's segments are supported by a corporate group that provides finance, treasury, information technology, legal, environmental health & safety, human resources and other administrative support. These corporate group overheads are allocated to the business segments based on budgeted gross salaries.

Each business segment assumes responsibility for its operating results measured as operating income or loss. Operating income is not defined under Canadian or U.S. GAAP. Operating income is calculated as net earnings before discontinued operations, income taxes, non-controlling interests, equity losses, foreign exchange gains and losses, and net interest expense.

The Generation segment owns coal, gas, wind, geothermal and hydro power plants in Canada, the United States and Australia, and generates its revenue from the sale of electricity, steam, gas and ancillary services. Generation expenses include Energy Marketing's intersegment charge for energy marketing and financial risk management services in the amount of $26.0 million (2004 – $26.0 million; 2003 – $24.8 million).

The Energy Marketing segment derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives not supported by TransAlta-owned generation assets. Energy Marketing also utilizes contracts of various durations for the forward sales of electricity and purchases of natural gas and transmission capacity to effectively manage available generating capacity and fuel and transmission needs on behalf of Generation. These results are included in the Generation segment. Operating expenses are net of the intersegment charges for provision of these energy marketing, financial risk management, commercial, portfolio and regulatory management services.

The accounting policies of the segments are the same as those described in *Note 1*. Intersegment transactions are accounted for on a cost recovery basis that approximates market rates. Segment revenues are net of intersegment transactions.

B. Reported Segment Earnings and Segment Assets

I. Earnings information

Year ended Dec. 31, 2005	Generation	Energy Marketing	Corporate	Total
Revenues	$ 2,607.5	$ 231.0	$ –	$ 2,838.5
Trading purchases	–	(174.1)	–	(174.1)
Fuel and purchased power	(1,201.8)	–	–	(1,201.8)
Gross margin	1,405.7	56.9	–	1,462.6
Operations, maintenance and administration	507.1	12.5	76.4	596.0
Depreciation and amortization	354.9	1.7	11.3	367.9
Taxes, other than income taxes	21.3	–	–	21.3
Operating expenses	883.3	14.2	87.7	985.2
Asset impairment charges	(36.2)	–	–	(36.2)
Operating income (loss) before corporate allocations	486.2	42.7	(87.7)	441.2
Corporate allocations	(76.4)	(11.3)	87.7	–
Operating income	$ 409.8	$ 31.4	$ –	$ 441.2
Foreign exchange gain				1.0
Net interest expense				(188.6)
Equity loss				(0.9)
Earnings from continuing operations before income taxes and non-controlling interests				$ 252.7

Year ended Dec. 31, 2004 *(Restated, Note 1)*	Generation	Energy Marketing	Corporate	Total
Revenues	$ 2,341.7	$ 244.5	$ –	$ 2,586.2
Trading purchases	–	(197.7)	–	(197.7)
Fuel and purchased power	(1,031.7)	–	–	(1,031.7)
Gross margin	1,310.0	46.8	–	1,356.8
Operations, maintenance and administration	476.0	5.3	66.2	547.5
Depreciation and amortization	343.5	2.0	12.0	357.5
Taxes, other than income taxes	20.5	–	–	20.5
Operating expenses	840.0	7.3	78.2	925.5
Prior period regulatory decision	–	(22.9)	–	(22.9)
Gain on sale of TransAlta Power partnership units	44.8	–	–	44.8
Gain on sale of Meridian Cogeneration Facility	17.7	–	–	17.7
Operating income (loss) before corporate allocations	532.5	16.6	(78.2)	470.9
Corporate allocations	(69.7)	(8.5)	78.2	–
Operating income	$ 462.8	$ 8.1	$ –	$ 470.9
Foreign exchange gain				0.7
Net interest expense				(207.4)
Equity loss				(8.5)
Earnings from continuing operations before income taxes and non-controlling interests				$ 255.7

Year ended Dec. 31, 2003 *(Restated, Note 1)*	Generation	Energy Marketing	Corporate	Total
Revenues	$ 2,304.8	$ 108.7	$ –	$ 2,413.5
Trading purchases	–	(97.4)	–	(97.4)
Fuel and purchased power	(990.8)	–	–	(990.8)
Gross margin	1,314.0	11.3	–	1,325.3
Operations, maintenance and administration	461.5	14.9	64.4	540.8
Depreciation and amortization	312.4	3.1	14.3	329.8
Taxes, other than income taxes	22.9	–	–	22.9
Operating expenses	796.8	18.0	78.7	893.5
Asset impairment and equipment cancellation charges	(90.3)	–	–	(90.3)
Gain on sale of Sheerness Generating Station	191.5	–	–	191.5
Gain on sale of land	10.5	–	–	10.5
Gain on sale of TransAlta Power partnership units	15.2	–	–	15.2
Operating income (loss) before corporate allocations	644.1	(6.7)	(78.7)	558.7
Corporate allocations	(69.9)	(8.8)	78.7	–
Operating income (loss)	$ 574.2	$ (15.5)	$ –	$ 558.7
Other income				(3.2)
Foreign exchange loss				(4.7)
Net interest expense				(212.1)
Equity loss				(6.0)
Earnings from continuing operations before income taxes and non-controlling interests				$ 332.7

II. Selected Balance Sheet Information

Dec. 31, 2005	Generation	Energy Marketing	Corporate	Total
Goodwill	**$ 108.1**	**$ 29.5**	**$ –**	**$ 137.6**
Total Segment assets	**$ 6,508.2**	**$ 293.2**	**$ 939.3**	**$ 7,740.7**

Dec. 31, 2004 *(Restated, Note 1)*	Generation	Energy Marketing	Corporate	Total
Goodwill	$ 112.7	$ 29.5	$ –	$ 142.2
Total Segment assets	$ 6,705.6	$ 221.6	$ 1,123.5	$ 8,050.7

III. Selected Cash Flow Information

Year ended Dec. 31, 2005	Generation	Energy Marketing	Corporate	Total
Capital expenditures	**$ 313.2**	**$ 1.5**	**$ 10.8**	**$ 325.5**

Year ended Dec. 31, 2004 *(Restated, Note 1)*	Generation	Energy Marketing	Corporate	Total
Capital expenditures	$ 332.3	$ 2.3	$ 11.1	$ 345.7

Year ended Dec. 31, 2003 *(Restated, Note 1)*	Generation	Energy Marketing	Corporate	Total
Capital expenditures	$ 421.1	$ 0.8	$ 12.5	$ 434.4
Acquisitions	$ 323.4	$ –	$ –	$ 323.4

IV. Reconciliation

Year ended Dec. 31	2005	2004 (Restated, Note 1)	2003 (Restated, Note 1)
Depreciation and amortization expense for reportable segments	**$ 367.9**	$ 357.5	$ 329.8
Mining equipment depreciation, included in fuel and purchased power	**49.9**	53.3	47.1
Accretion expense, included in depreciation and amortization expense	**(19.3)**	(19.3)	(22.0)
Other	**2.4**	(1.4)	14.0
Depreciation and amortization expense per statements of cash flows	**$ 400.9**	$ 390.1	$ 368.9

C. Geographic Information

I. Revenues

Year ended Dec. 31	2005	2004 (Restated, Note 1)	2003 (Restated, Note 1)
Canada	**$ 1,716.1**	$ 1,662.7	$ 1,412.4
U.S.	**1,026.2**	833.0	918.8
Australia	**96.2**	90.5	82.3
	$ 2,838.5	$ 2,586.2	$ 2,413.5

II. Property, Plant and Equipment and Goodwill

	PP&E		Goodwill	
Dec. 31	2005	2004 (Restated, Note 1)	2005	2004
Canada	**$ 3,789.3**	$ 3,858.7	**$ 56.5**	$ 56.5
U.S.	**1,585.0**	1,657.2	**81.1**	85.7
Australia	**171.2**	186.7	**–**	–
	$ 5,545.5	$ 5,702.6	**$ 137.6**	$ 142.2

NOTE
3. DISCONTINUED OPERATIONS

A. Transmission

In June 2004, a settlement was reached to finalize the sale of the corporation's Transmission operations. In April 2002, the Transmission operations were sold for proceeds of $820.7 million. The disposal resulted in an after-tax gain on sale of $120.0 million that was recorded in 2002. During 2004, final working capital adjustments were made to reflect post-closing adjustments and other provisions related to closing costs, which resulted in an additional $9.6 million after-tax gain.

B. Alberta Distribution and Retail (D&R)

In August 2000, the corporation sold its Alberta D&R business for proceeds of $857.3 million. The original gain recorded on this transaction was $262.4 million. During the fourth quarter of 2005, the corporation settled an outstanding income tax dispute related to this business. Included in earnings from discontinued operations for the year ended Dec. 31, 2005 is $12.0 million related to this matter. The settlement of this issue brings the final gain on disposal of the Alberta D&R business to $274.4 million. In 2005, $12.0 million related to the favourable resolution of a tax dispute related to the Transmission operations was included in net earnings.

NOTE
4. ACQUISITIONS AND DISPOSALS

A. Acquisitions

On Jan. 29, 2003, the corporation acquired a 50 per cent interest in CE Gen for US$240.0 million (Cdn$366.6 million). The acquisition was accounted for using the purchase method of accounting. CE Gen is controlled jointly by TransAlta and MidAmerican Energy Holdings Company (MidAmerican). As such, the financial results of CE Gen subsequent to the acquisition date are proportionately consolidated with those of TransAlta and are included in the Generation segment. The purchase price was finalized in the second quarter of 2003 and is presented below:

Net assets acquired at assigned values:	
Working capital, including cash of $43.2 million	$ 60.3
Restricted cash	57.9
Current income tax receivable	2.4
Property, plant and equipment	414.6
Intangibles	610.5
Goodwill	108.9
Note receivable	90.0
Non-recourse long-term debt, including current portion	(717.4)
Future income tax liability	(216.0)
Non-controlling interests	(44.6)
Total	$ 366.6
Consideration:	
Cash	$ 366.6

Acquired intangibles relate to the fair value of power sale contracts. The amount is being amortized on a straight-line basis over the remaining contract period *(Note 7)*.

Goodwill resulted from the purchase of PP&E with no tax basis.

The restricted cash is comprised of debt service funds which are legally restricted, and require the maintenance of specific minimum balances equal to the next debt service payment, and amounts restricted for capital and maintenance expenditures. The amount of restricted cash acquired has been reduced subsequent to the acquisition primarily as a result of TransAlta issuing a letter of credit in lieu of holding the restricted cash *(Note 10)*.

B. Disposals

On Dec. 1, 2004, TransAlta completed the sale of its 50 per cent interest in the 220 megawatt (MW) Meridian Cogeneration Facility located in Lloydminster, Saskatchewan to TransAlta Cogeneration, L.P. (TA Cogen), owned 50.01% by TransAlta and 49.99% by TransAlta Power, L.P. (TA Power), for its fair value of $110.0 million. TA Cogen financed the acquisition through the use of $50.0 million of cash on hand, by the issuance of $30.0 million of units to each of TransAlta Energy Corporation (TEC) and TA Power and by an advance to TEC for $30.0 million. The advance outstanding at Dec. 31, 2005 was $5.0 million (2004 – $18.0 million) and is included in accounts receivable.

On July 31, 2003, TransAlta completed the sale of its 50 per cent interest in the two-unit 756 MW coal-fired Sheerness Generating Station to TA Cogen. As part of the financing, and concurrent with the sale, TA Power issued 17.75 million partnership units and 17.75 million warrants to the public, and 17.75 million partnership units to TransAlta. As a result of the unit issuance, TransAlta's ownership interest in TA Power on July 31, 2003 was approximately 26 per cent. Each warrant, when exercised, was exchangeable for one TA Power unit at any time until Aug. 3, 2004. As the warrants were exercised, TransAlta sold TA Power units back to TA Power for $9.30 per unit, reducing its ownership interest in TA Power and increasing cash proceeds. As a result of exercising warrants and the subsequent sale of TA Power units by the corporation, TransAlta's ownership interest in TA Power was reduced to 0.01 per cent held by TransAlta Power Ltd., the general partner of TA Power, as at Dec. 31, 2004.

As a result of the sale, TransAlta realized a gain on sale of $191.5 million recorded in 2003, which included the realization of the $119.8 million 1998 deferred gain related to the disposition of the Ottawa, Windsor and Mississauga cogeneration facilities. Proceeds from the sale of the Sheerness Generating Station were used to repay debt. For the year ended Dec. 31, 2005, TransAlta recognized $ nil (2004 – $44.8 million) of dilution gains on the exercise of warrants and subsequent sale of units. Prior to Aug. 3, 2004, 10.4 million warrants were exercised while a further 0.3 million units were sold in the third quarter of 2004 subsequent to the expiry of the warrants. In the fourth quarter of 2004, TransAlta sold 7.1 million units for net proceeds of $64.0 million.

On Dec. 31, 2003, TransAlta completed the sale of 539 acres of undeveloped land at Seebe, Alberta for $11.0 million, resulting in a pre-tax gain on sale of $10.5 million.

On May 9, 2003, TransAlta sold the Calgary head office building for $65.8 million, which was an agreed upon value. TransAlta is leasing the property for a term of 20 years. The lease is accounted for as an operating lease.

NOTE
5. INVESTMENTS

Year Ended Dec. 31	2005	2004
		(Restated, Note 1)
Investment in oil and gas companies	$ 3.0	$ 3.0
Investment in Mexico	411.3	418.3
	$ 414.3	$ 421.3

Effective Jan. 1, 2005, TransAlta adopted the CICA's Accounting Guideline 15, Consolidation of Variable Interest Entities. Accordingly, the Mexican subsidiaries owning the Chihuahua and Campeche plants are presented as equity investments.

In 2003, as the result of its annual review of its long-term investments, the corporation recorded a $6.2 million charge to recognize an other than temporary decline in fair value. The charge is included in corporate operations, maintenance and administrative expenses.

Also in 2003, the corporation sold its 8.82 per cent interest in the Goldfields gas pipeline, for proceeds of AUD$24.1 million (Cdn$21.6 million), which approximated book value.

NOTE
6. PROPERTY, PLANT AND EQUIPMENT

Year ended Dec. 31		2005			2004		
	Depreciation rates	Cost	Accumulated depreciation and amortization	Net book value	Cost	Accumulated depreciation and amortization	Net book value
							(Restated, Note 1)
Thermal generation	3% – 33%	$ 3,244.8	$ 1,180.1	$ 2,064.7	$ 3,129.4	$ 1,078.3	$ 2,051.1
Thermal environmental equipment	4% – 13%	608.6	270.4	338.2	621.5	253.1	368.4
Mining property & equipment	4% – 33%	747.3	349.0	398.3	732.6	353.4	379.2
Gas generation	2% – 50%	2,492.4	677.1	1,815.3	2,153.9	539.9	1,614.0
Geothermal generation	3% – 33%	389.2	96.9	292.3	394.6	85.1	309.5
Hydro generation	2% – 5%	348.9	197.2	151.7	343.5	189.1	154.4
Wind generation	2% – 3%	205.5	17.9	187.6	206.8	10.7	196.1
Capital spares and other	2% – 50%	204.4	45.8	158.6	246.8	51.4	195.4
Assets under construction	–	10.7	–	10.7	322.8	–	322.8
Coal rights[1]	–	79.1	17.1	62.0	73.9	18.4	55.5
Land	–	40.0	–	40.0	38.3	–	38.3
Transmission systems	2% – 20%	40.9	14.8	26.1	31.3	13.4	17.9
		$ 8,411.8	$ 2,866.3	$ 5,545.5	$ 8,295.4	$ 2,592.8	$ 5,702.6

1 Coal rights are amortized on a unit of production basis, based on the estimated mine reserve.

The corporation capitalized $3.4 million of interest to PP&E in 2005 (2004 – $20.0 million, 2003 – $43.0 million) related to the construction of Genesee 3, the Summerview wind farm and the McBride Lake wind farm.

For the year ended Dec 31, 2005, TA Cogen, a subsidiary that is owned 50.01 per cent by TransAlta and 49.99 per cent by TA Power, a publicly traded entity, recorded an impairment charge of $78.3 million in respect of the Ottawa facility as the net book value of that facility exceeded its net recoverable amount, measured as the future cash flows from the facility. The net book value of the Ottawa facility in the accounts of the corporation is lower than that in TA Cogen. The carrying value in TransAlta is fully recoverable from future cash flows of the facility. The difference in net book value between the accounts of the corporation and TA Cogen is due to the higher purchase price of the plant by TA Cogen. The corporation has recognized an increase in depreciation expense of $36.2 million related to TA Power's share of the impairment charge. This amount is offset by a recovery in the earnings attributable to non-controlling interests in the corporation's income statement.

In 2003, the corporation concluded that the book value of its turbine inventory was unlikely to be recovered. As a result, TransAlta recorded an $84.7 million pre-tax impairment charge to write the turbines down to fair value, included in gas generation. Fair value was based on quoted market prices.

In 2003, TransAlta recorded a $5.6 million pre-tax impairment charge on the Binghamton plant to reduce the plant's book value to fair value, based on the present value of expected future cash flows.

NOTE 7.

INTANGIBLE ASSETS

Year ended Dec. 31	2005			2004		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Sales contracts[1]	**$ 473.6**	**$ 123.8**	**$ 349.8**	$ 488.7	$ 96.4	$ 392.3

1 *Intangible assets consist of power sale contracts, with rates higher than market rates at the date of acquisition, acquired in the purchase of CE Gen. Sales contracts are valued at cost and are amortized on a straight-line basis over the remaining contract period, which ranges from seven to 30 years at the date of acquisition.*

NOTE 8.

OTHER ASSETS

Year ended Dec. 31	2005	2004
		(Restated, Note 1)
Cross-currency interest rate swaps and foreign currency forward contracts *(Note 18)*	**$ 102.6**	$ 375.3
Interest rate swaps *(Note 18)*	**38.4**	44.4
Deferred financing costs	**18.7**	22.5
Deferred licence fees	**27.1**	27.1
Deferred contract costs	**17.1**	21.1
Deferred project development costs and other	**2.6**	2.3
Long-term gas transportation deals	**4.4**	8.0
	210.9	500.7
Less current portion	**(10.9)**	(301.0)
	$ 200.0	$ 199.7

Deferred financing costs are costs associated with the issuance of long-term debt and preferred securities and are being amortized on a straight-line basis over the term of the related issue.

Deferred licence fees consist primarily of an Australian licence which is being amortized on a straight-line basis over the useful life of the power station assets to which the licence relates.

Deferred contract costs consist of prepayments related to long-term contracts, which are being amortized on a straight-line basis over the term of the related contracts.

NOTE 9.

SHORT-TERM DEBT

Year ended Dec. 31	2005		2004	
	Outstanding	Interest[1]	Outstanding	Interest[1]
Commercial paper	**$ 12.5**	**3.3%**	$ 34.4	2.6%
Bank debt	**0.6**	**–**	–	–
	$ 13.1		$ 34.4	

1 *Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.*

NOTE

10. LONG-TERM DEBT AND NET INTEREST EXPENSE

A. Amounts Outstanding

As at Dec. 31	2005		2004	
	Outstanding	Interest[1]	Outstanding	Interest[1]
			(Restated, Note 1)	
Debentures, due 2006 to 2033[2]	**$ 1,496.1**	**6.2%**	$ 1,388.5	6.5%
Senior notes, US$600.0 million[3]	**694.0**	**6.3%**	733.6	6.3%
Non-recourse debt[4]	**363.8**	**7.7%**	423.3	6.9%
Notes payable – Windsor plant, due 2006 to 2014[5]	**51.1**	**7.4%**	55.0	7.4%
Preferred securities, due 2050[6]	**175.0**	**7.8%**	475.0	7.8%
Other	**–**	**–**	0.8	8.0%
	$ 2,780.0		$ 3,076.2	
Less current portion	**396.4**		580.1	
	$ 2,383.6		$ 2,496.1	

1 *Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.*

2 *Debentures: The debentures bear interest at fixed rates ranging from 4.2 per cent to 7.3 per cent. A floating charge on the property and assets of TransAlta Utilities (TAU) has been provided as collateral for $365.0 million of the debentures as at Dec. 31, 2005. The interest rate on $375.0 million of the debentures amount has been converted to floating rates based on bankers' acceptance rates using interest rate swaps maturing between 2006 to 2011* (Note 18). *Debentures of $100.0 million maturing in 2023 and $50.0 million maturing in 2033 are redeemable at the option of the holder in 2008 and 2009, respectively. Debentures in the amount of $150.0 million matured in 2005, with the holders of $141.1 million of the debentures exercising their option to extend their maturity until 2030 at an interest rate of 6.9 per cent. Debentures of $200 million were issued in December 2005 and mature in December 2007, they bear interest at a fixed rate 4.2 per cent.*

3 *Senior notes: The notes bear an interest rate of 5.75 per cent and mature in 2013. The US$300.0 million has been converted to a floating rate based on LIBOR using receive fixed, pay floating interest rate swaps maturing in 2013. The notes bear interest at 6.75 per cent and mature on July 15, 2012. All senior notes have been designated as a hedge of the corporation's net investment in U.S. and Mexican operations* (Note 18).

4 *Non-recourse debt: The debt consists of project financing debt, debt securities and senior secured bonds of CE Gen. The related assets have been pledged as security for the project financing debt. Maturity dates range from 2004 to 2008, with a fixed interest rate of 8.56 per cent. The debt securities are non-recourse, have maturity dates ranging from 2005 to 2018 and interest rates ranging from 7.48 per cent to 8.30 per cent. The outstanding balance of the non-recourse senior secured bonds as of Dec. 31, 2005 was $309.0 million and bears interest at 7.42 per cent, and is due in 2018.*

5 *Notes payable – Windsor plant: The Windsor plant notes bear interest at fixed rates and are recourse to the corporation through a standby letter of credit.*

6 *Preferred securities: The preferred securities bear interest of 7.75 per cent and are due in 2050. The preferred securities are subordinated and unsecured and the corporation may redeem the preferred securities in whole or in part in 2006 at a redemption price equal to 100 per cent of the principal amount of the preferred securities plus accrued and unpaid distributions thereon to the date of such redemption. The corporation may elect to defer coupon payments on the preferred securities and settle deferred coupon payments in either cash or common shares of the corporation. Historically, the coupon payments have been in cash; therefore, the preferred securities have no dilutive effect on earnings per share. Supplemental diluted earnings per share for 2005 from continuing operations and net earnings as though the coupon payments were settled with shares were $0.94 (2004 – $0.82, 2003 – $1.25, 2002 – $0.39) and $1.00 (2004 – $0.87, 2003 – $1.25, 2002 – $1.16). Interest accretion at the coupon rate is included in interest expense. In February 2005, the corporation redeemed $175.0 million of preferred securities that had an interest rate of 7.5 per cent and $125.0 million of preferred securities that had an interest rate of 8.15 per cent.*

B. Principal Repayments

2006	$ 396.4
2007	249.4
2008	157.6
2009	239.7
2010	29.4
2011 and thereafter	1,707.5
Total	$ 2,780.0

C. Interest Expense

Year ended Dec. 31	2005	2004	2003
		(Restated, Note 1)	(Restated, Note 1)
Interest on recourse and non-recourse debt	**$ 184.2**	$ 192.8	$ 222.8
Interest on preferred securities	**16.5**	44.5	36.8
Interest income	**(8.7)**	(9.9)	(4.5)
Capitalized interest	**(3.4)**	(20.0)	(43.0)
Net interest expense	**$ 188.6**	$ 207.4	$ 212.1

D. Guarantees

In the normal course of operations, TransAlta and certain of its subsidiaries enter into agreements to provide financial or performance assurances to third parties. This includes guarantees and letters of credit which are entered into to support or enhance creditworthiness in order to facilitate the extension of sufficient credit for Energy Marketing trading activities, treasury hedging, Generation construction projects, equipment purchases and mine reclamation obligations.

At Dec. 31, 2005, the corporation had letters of credit outstanding of $216.9 million and US$415.3 million. The letters of credit were issued to counterparties that have credit exposure to certain subsidiaries. If the corporation or its subsidiary does not pay amounts due under the contract, the counterparty may present its claim for payment to the financial institution, which in turn will request payment from the corporation. Any amounts owed by the corporation or its subsidiaries are reflected in the consolidated balance sheet. All letters of credit expire in 2006 and 2007.

The corporation has arranged for the issuance of a surety bond in the amount of US$192.0 million in support of mine reclamation obligations at the Centralia mine.

TransAlta has provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions in various derivatives. To the extent liabilities related to these guaranteed contracts exist for trading activities, they are included in the consolidated balance sheet. To the extent liabilities exist related to these guaranteed contracts for hedges, they are not recognized on the consolidated balance sheet. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at Dec. 31, 2005 were to a maximum of $1.8 billion. In addition, the corporation has a number of unlimited guarantees. The fair value of the trading and hedging positions under contracts where TransAlta has a net liability at Dec. 31, 2005, under the limited and unlimited guarantees, was $559.7 million (2004 – $345.2 million).

TransAlta has also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at Dec. 31, 2005 was $645.3 million (2004 – $662.5 million). To the extent actual obligations exist under the performance guarantees at Dec. 31, 2005, they are included in accounts payable and accrued liabilities.

The corporation has approximately $1.2 billion of undrawn collateral available to secure these exposures.

NOTE 11. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

As at Dec. 31	2005	2004 (Restated, Note 1)
Asset retirement obligations	**$ 249.2**	$ 238.1
Deferred revenues and other	**21.8**	30.0
Power purchase arrangement in limited partnership	**29.2**	31.4
Accrued benefit liability *(Note 17)*	**49.3**	58.2
Cross-currency interest rate swaps and foreign currency forward contracts *(Note 18)*	**14.8**	270.4
Fair value of swap transaction with limited partnership	**1.6**	4.9
	$ 365.9	$ 633.0
Less current portion	**(0.4)**	(241.5)
	$ 365.5	$ 391.5

A reconciliation between the opening and closing asset retirement obligation balances is provided below:

Balance, Dec. 31, 2003	$ 253.3
Liabilities incurred in period	21.8
Liabilities settled in period	(19.7)
Accretion expense	19.3
Revision in estimated cash flows	(22.3)
Change in foreign exchange rates	(14.3)
Balance, Dec. 31, 2004	$ 238.1
Liabilities incurred in period	12.3
Liabilities settled in period	(29.4)
Accretion expense	19.3
Revisions in estimated cash flows	25.6
Change in foreign exchange rates	(16.7)
Balance, Dec. 31, 2005	**$ 249.2**

TransAlta estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $1.4 billion, which will be incurred between 2007 and 2072. The majority of the costs will be incurred between 2020 and 2030. A discount rate of eight per cent was used to calculate the carrying value of the asset retirement obligations. At Dec. 31, 2005, the corporation had a surety bond in the amount of US$192.0 million in support of future retirement obligations at the Centralia mine. At Dec. 31, 2005, the corporation had letters of credit in the amount of $60.8 million in support of future retirement obligations at the Alberta mines.

The Power Purchase Arrangement (PPA) in the limited partnership represents the fair value adjustments for the Sheerness Generating Station to deliver power at less than the prevailing market price at the time of the acquisition of the plant by TA Cogen.

NOTE 12.

NON-CONTROLLING INTERESTS

A. Statements of Earnings

Year ended Dec. 31	2005	2004	2003
TA Power's limited partnership interest in TA Cogen *(Note 21)*	**$ 2.1**	$ 31.5	$ 21.3
Other shareholders' interests	**16.4**	14.5	12.9
	$ 18.5	$ 46.0	$ 34.2

B. Balance Sheets

As at Dec. 31	2005	2004
TA Power's limited partnership interest in TA Cogen	**$ 525.0**	$ 582.4
Other shareholders' interests	**33.6**	34.0
	$ 558.6	$ 616.4

Other shareholders' interests represents the 25 per cent interest in the Saranac Partnership not owned by CE Gen.

NOTE 13.

COMMON SHARES

A. Issued and Outstanding

The corporation is authorized to issue an unlimited number of voting common shares without nominal or par value.

Year ended Dec. 31	2005		2004		2003	
	Common shares (millions)	Amount	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of year	**194.1**	**$ 1,611.9**	190.7	$ 1,555.7	169.8	$ 1,226.2
Issued as a public offering and other	**–**	**–**	–	–	17.3	270.4
Issued under dividend reinvestment and share purchase plan	**3.5**	**68.1**	3.4	55.3	3.3	54.6
Issued on purchase of Vision Quest	**–**	**0.2**	–	0.7	0.1	1.7
Issued for cash under stock option plans	**1.0**	**16.3**	0.1	1.1	0.1	1.4
Issued under Performance Share Ownership Plan	**0.1**	**1.2**	–	1.1	0.1	1.4
Repurchased by the corporation	**–**	**–**	(0.1)	(1.2)	–	–
Employee share purchase loans	**–**	**0.2**	–	(0.8)	–	–
	198.7	**$ 1,697.9**	194.1	$ 1,611.9	190.7	$ 1,555.7

At Dec. 31, 2005, the corporation had 198.7 million (2004 – 194.1 million; 2003 – 190.7 million) common shares issued and outstanding, plus outstanding employee stock options to purchase an additional 2.9 million shares (2004 – 2.9 million; 2003 – 3.1 million).

In February 2004, TransAlta announced a normal course issuer bid to repurchase up to 3.0 million common shares for cancellation. In 2005, no shares were repurchased. In 2004, 143,500 shares were repurchased and no shares were repurchased during 2003. The $1.1 million in 2004 in excess of the repurchase price over the average net book value of the common shares was charged to retained earnings.

In March 2003, the corporation issued 15.0 million common shares for gross proceeds of $240.0 million, with issue costs of $8.0 million. The offering included an option for the underwriters to purchase a further 2.25 million common shares for $36.0 million. This option was fully exercised on April 17, 2003 with issue costs of $3.0 million.

B. Shareholder Rights Plan

The primary objective of the shareholder rights plan is to provide the corporation's Board of Directors sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the corporation and to provide every shareholder with an equal opportunity to participate in such a bid. The plan was originally approved in 1992, and has been revised from time to time for conformity with current practices.

When an acquiring shareholder acquires 20 per cent or more of the outstanding common shares of the corporation and that shareholder does not make a bid for all of the common shares outstanding, each shareholder other than the acquiring shareholder may receive one right for each common share owned. Each right will entitle the holder to acquire an additional $160 worth of common shares for $80.

C. Dividend Reinvestment and Share Purchase Plan

Under the terms of the dividend reinvestment and share purchase plan, participants are able to purchase additional common shares by reinvesting dividends. Common shares will be issued from treasury. In 2005, 3.5 million (2004 – 3.4 million, 2003 – 3.3 million) common shares were purchased under this program for $68.1 million (2004 – $55.3 million, 2003 – $54.6 million).

D. Earnings Per Share (EPS)

Year ended Dec. 31	2005		2004		2003	
	Numerator	Denominator	Numerator	Denominator	Numerator	Denominator
Basic EPS from continuing operations	**186.8**	**196.8**	160.6	192.7	234.2	185.3
Impact of PSOP	**–**	**0.4**	–	0.1	–	0.1
Diluted EPS from continuing operations	**186.8**	**197.2**	160.6	192.8	234.2	185.4

NOTE 14. STOCK-BASED COMPENSATION PLAN

At Dec. 31, 2005, the corporation had three types of stock-based compensation plans and an employee share purchase plan.

The corporation is authorized to grant employees options to purchase up to an aggregate of 13.0 million common shares at prices based on the market price of the shares as determined on the grant date. The corporation has reserved 13.0 million common shares for issue.

A. Fixed Stock Option Plans

I. Management Plan

The granting of options under this fixed stock option plan was discontinued in 1997. Options were granted under this plan to certain eligible employees. The options could not be exercised until one year after grant and thereafter at an amount not exceeding 20 per cent of the grant per year on a cumulative basis until the sixth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

II. Canadian Employee Plan

This plan is offered to all full-time and part-time employees in Canada at or below the level of manager. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

III. Alberta Distribution and Retail (D&R) Plan

This plan is offered to all full-time and part-time employees of the Alberta D&R business segment. Options granted under this plan could not be exercised until the date of the closing of the Alberta D&R sale on Aug. 31, 2000, after which the entire grant could be exercised for up to three years after the closing. The outstanding options under this plan at Dec. 31, 2003 expired in January 2004.

IV. U.S. Plan

This plan is offered to all full-time and part-time employees in the United States at or below the level of manager. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

V. Australian Phantom Plan

This plan came into effect in 2001 and was offered to all full-time and part-time employees in Australia, excluding directors and officers. Options under this plan are not physically granted; rather, employees receive the equivalent value of shares in cash when exercised. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

VI. Mexican Phantom Plan

The Mexican phantom plan mirrors the rules of the Australian plan, with the first grant occurring in 2005.

	Management plan		Canadian employee plan		Alberta D&R plan		U.S. employee plan		Australian phantom plan		Mexican phantom plan	
	Number of share options (millions)	Weighted average exercise price	Number of share options (millions)	Weighted average exercise price	Number of share options (millions)	Weighted average exercise price	Number of share options (millions)	Weighted average exercise price	Number of share options (millions)	Weighted average exercise price	Number of share options (millions)	Weighted average exercise price
Outstanding, Jan.1, 2003	0.1	$ 14.91	1.6	$ 21.89	0.1	$ 14.20	1.1	$ 13.61	0.1	$ 22.00	–	$ –
Granted	–	–	0.1	17.11	–	–	–	–	–	–	–	–
Exercised	–	–	–	–	(0.1)	14.20	–	–	–	–	–	–
Cancelled or expired	–	–	(0.1)	21.39	–	–	–	–	–	–	–	–
Outstanding, Dec. 31, 2003	0.1	$ 14.91	1.6	$ 21.18	–	$ –	1.1	$ 13.61	0.1	$ 22.00	–	$ –
Granted	–	–	–	–	–	–	–	–	–	–	–	–
Exercised	–	–	(0.1)	22.52	–	–	–	–	–	–	–	–
Cancelled or expired	–	–	–	–	–	–	(0.1)	13.47	–	–	–	–
Outstanding, Dec. 31, 2004	0.1	$ 14.91	1.5	$ 21.93	–	$ –	1.0	$ 13.56	0.1	$ 22.00	–	$ –
Granted	–	–	0.7	17.80	–	–	0.4	14.48	–	17.80	–	17.80
Exercised	(0.1)	14.82	(0.2)	18.20	–	–	(0.6)	13.73	–	21.56	–	–
Cancelled or expired	–	–	(0.1)	21.04	–	–	–	13.85	–	20.12	–	17.80
Outstanding, Dec. 31, 2005	**–**	**$ 15.00**	**1.9**	**$ 20.85**	**–**	**$ –**	**0.8**	**$ 14.03**	**0.1**	**$ 20.37**	**–**	**$ 17.80**

	Options outstanding			Options exercisable	
	Number outstanding at Dec. 31, 2005 (millions)	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable at Dec. 31, 2005 (millions)	Weighted average exercise price
Range of exercise prices					
$13.12 – $18.00	**1.7**	**7.8**	**$ 16.72**	**0.5**	**$ 15.47**
$18.01 – $23.00	**0.5**	**6.0**	**21.05**	**0.4**	**21.10**
$27.70	**0.5**	**5.3**	**27.70**	**0.5**	**27.70**
$13.12 – $27.70	**2.7**	**7.0**	**$ 19.45**	**1.4**	**$ 21.29**

B. Performance Stock Option Plan

In 1999, the corporation expanded enrolment in the share option program to include all Canadian employees of the corporation, excluding the level of director and above, by issuing stock options with an expiry date of 2009 and vesting dependent upon achieving certain earnings per share targets.

Year ended Dec. 31	2005		2004		2003	
	Number of share options (millions)	Weighted average exercise price	Number of share options (millions)	Weighted average exercise price	Number of share options (millions)	Weighted average exercise price
Outstanding, beginning of year	**0.2**	**$ 22.44**	0.2	$ 22.44	0.2	$ 22.44
Exercised	**–**	**21.33**	–	–	–	–
Cancelled or expired	**–**	**23.05**	–	–	–	–
Outstanding, end of year	**0.2**	**$ 22.62**	0.2	$ 22.44	0.2	$ 22.44

At Dec. 31, 2005, the corporation had 9,333 options under this plan with an exercise price of $14.15 and a weighted average remaining contractual life of 4.0 years and 185,000 options with an exercise price of $23.05 and a weighted average remaining contractual life of 3.1 years outstanding. At Dec. 31, 2005, all outstanding options had vested.

C. Performance Share Option Plan (PSOP)

Under the terms of the PSOP, which commenced in 1997, the corporation was authorized to grant to employees and directors up to an aggregate of 2.0 million common shares. The number of common shares which could be issued under both the PSOP and the share option plans, however, could not exceed 6.0 million common shares. Participants in the PSOP receive awards which, after three years, make them eligible to receive a set number of common shares or cash equivalent up to the maximum of the award amount plus any accrued dividends thereon. The actual number of common shares or cash equivalent a participant may receive is determined by the percentile ranking of the total shareholder return over three years of the corporation's common shares amongst the companies comprising the S&P/TSX composite index.

On Dec. 31, 2001, the plan was modified so that after three years, once the PSOP eligibility has been determined, 50 per cent of the shares may be released to the participant, while the remaining 50 per cent will be held in trust for one additional year. In addition, the number of common shares the corporation is authorized to grant under the terms of the PSOP was increased to 4.0 million common shares and the maximum number of common shares that may be issued under both the PSOP and share option plans was increased to 13.0 million common shares.

Year ended Dec. 31	2005	2004	2003
Number of awards outstanding, beginning of year	**1.5**	1.5	1.3
Granted	**0.4**	0.4	0.7
Awarded	**(0.1)**	–	(0.1)
Cancelled or expired	**(0.7)**	(0.4)	(0.4)
Number of awards outstanding, end of year	**1.1**	1.5	1.5

In 2005, PSOP compensation expense was $10.6 million (2004 – $3.4 million, 2003 – $nil), which is included in operations, maintenance and administration expense in the statements of earnings. In 2005, 65,332 common shares were issued at $25.41 per share. In 2004, 16,457 common shares were issued at $17.11 per share and 44,846 common shares were issued at $18.53 per share. In 2003, 83,300 common shares were issued at $17.11 per share.

D. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the corporation will extend an interest-free loan (up to 30 per cent of an employee's base salary) to employees below executive level and allow for payroll deductions over a three-year period to repay the loan. Executives are no longer eligible for this program in accordance with the Sarbanes-Oxley legislation. The corporation will purchase these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares are handled in the same manner. At Dec. 31, 2005, accounts receivable from employees under the plan totalled $0.6 million (2004 – $0.8 million).

E. Stock-Based Compensation

At Dec. 31, 2005, the corporation had 2.9 million outstanding employee stock options (Dec. 31, 2004 – 2.9 million).

The corporation uses the fair value method of accounting for awards granted under its fixed stock option plans and its performance stock option plan. In March 2005, 1.2 million options were granted. One quarter of the options granted vest on each of the first, second, third and fourth anniversaries of the date of grant and expire after 10 years. The estimated fair value of these options granted was determined using the binomial model using the following assumptions, resulting in a fair value of $6.84 per option.

	2005
Risk-free interest rate	**4.3%**
Life of the options (years)	**10**
Dividend rate	**5.6%**
Volatility in the price of the corporation's shares	**47.0%**

As disclosed in *Note 1(P)*, on Jan. 1, 2003 the corporation adopted the fair value method of accounting for stock-based compensation prospectively, under which a compensation expense is measured at the grant date and recognized over the service period. In 2005, the corporation granted options to purchase 1.2 million common shares of the corporation to its employees (2004 – nil, 2003 – nil) at a weighted average exercise price of $17.80. The following table provides pro forma measures of net earnings and earnings per share had compensation expense been recognized based on the estimated fair value of the options on the grant date in accordance with the fair value method of accounting for stock based compensation for grants made in 2002:

Year ended Dec. 31	2005	2004	2003
Reported net earnings	$ **198.8**	$ 170.2	$ 234.2
Compensation expense	**1.5**	1.7	2.6
Pro forma net earnings	$ **197.3**	$ 168.5	$ 231.6
Reported basic earnings per share	$ **1.01**	$ 0.88	$ 1.26
Compensation expense per share	**0.01**	0.01	0.01
Pro forma basic earnings per share	$ **1.00**	$ 0.87	$ 1.25
Reported diluted earnings per share	$ **1.01**	$ 0.88	$ 1.26
Compensation expense per share	**0.01**	0.01	0.01
Pro forma diluted earnings per share	$ **1.00**	$ 0.87	$ 1.25

The estimated fair value of these stock options granted in 2002 and prior was determined using the binomial model using the following assumptions, resulting in a weighted-average fair value of $4.25 in 2002.

	2002
Risk-free interest rate	5.9%
Expected hold period to exercise (years)	7.0
Volatility in the price of the corporation's shares	28.3%

NOTE
15. PRIOR PERIOD REGULATORY DECISION

At Dec. 31, 2000, the corporation had made a provision of US$28.8 million against US$58.0 million of receivables outstanding related to sales to the California market. US$5.0 million of this amount was received during 2001. In March 2004, TransAlta recorded an additional pre-tax provision of US$17.2 million ($22.9 million).

The U.S. Federal Energy Regulatory Commission (FERC) has provided TransAlta with an opportunity to petition for relief from refund obligations. To be successful in such a petition for relief we will be required to demonstrate that, as a result of the refund methodology, TransAlta suffered operating losses in respect of California transactions during the refund period. On Aug. 8, 2005, FERC issued an order detailing the methodology for a petition for relief from refund obligations. TransAlta prepared a petition for relief from the refund obligation and filed it with FERC. The California Independent System Operator (CAISO) and California Power Exchange (CALPX) have reviewed and commented on our petition and TransAlta replied to the CAISO and CALPX comments on Oct. 17, 2005. On Jan. 26, 2006, FERC conditionally accepted TransAlta's petition for relief, subject to modification. This revised compliance filing is due Feb. 10, 2006.

NOTE

16. INCOME TAXES

The corporation follows Canadian GAAP for non-regulated entities for all electricity generation operations and as a result, future income taxes have been recorded for all operations.

A. Statements of Earnings

I. Rate Reconciliations

	2005	2004 (Restated, Note 1)	2003 (Restated, Note 1)
Earnings from continuing operations before income taxes	**$ 234.2**	$ 209.7	$ 298.5
Statutory Canadian federal and provincial income tax rate	**33.6%**	33.9%	36.8%
Expected taxes on income	**$ 78.7**	$ 71.0	$ 109.8
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(23.3)**	(19.2)	(22.9)
Resolution of uncertain tax positions	**(13.0)**	(6.8)	–
Resource allowance (net of non-deductible royalties)	**(1.4)**	(1.6)	(2.5)
Manufacturing and processing rate reduction	**(1.3)**	(1.7)	(3.5)
Large corporations tax (net of surtax)	**10.0**	10.3	9.5
Effect of tax rate changes	**(3.8)**	(7.8)	(4.4)
Unrecognized future income tax assets	**1.5**	6.1	1.5
Non-taxable portion of gain on disposition of assets	**–**	–	(22.7)
Other	**–**	(1.2)	(0.5)
Income tax expense	**$ 47.4**	$ 49.1	$ 64.3
Effective tax rate	**20.2%**	23.4%	21.5%

The corporation's operations are complex, and the computation and provision for income taxes involves tax interpretations, regulations and legislation that are continually changing. The corporation's tax filings are subject to audit by taxation authorities. The outcome of some audits may change the tax liability of the corporation. Management believes it has adequately provided for income taxes based on all information currently available.

II. Components of Income Tax Expense

	2005	2004 (Restated, Note 1)	2003 (Restated, Note 1)
Current tax expense	**$ 41.8**	$ 36.1	$ 51.0
Future income tax expense related to the origination and reversal of temporary differences	**9.4**	20.8	17.7
Future income tax benefit resulting from changes in tax rates or laws	**(3.8)**	(7.8)	(4.4)
Income tax expense	**$ 47.4**	$ 49.1	$ 64.3

B. Balance Sheets

Significant components of the corporation's future income tax assets and liabilities are as follows:

	2005	2004
Net operating and capital loss carry forwards	**$ 260.5**	$ 275.7
Asset retirement obligation	**82.6**	88.9
Unrealized losses on electricity trading contracts	**10.5**	29.7
Property, plant and equipment	**(947.8)**	(949.4)
Unrealized gains on electricity trading contracts	**(12.6)**	(36.4)
Other deductible temporary differences	**22.0**	30.0
	$ (584.8)	$ (561.5)

Presented in the balance sheet as follows:

	2005	2004
Assets		
Current	$ 26.6	$ 21.5
Long term	147.1	132.0
Liabilities		
Current	(18.2)	(11.1)
Long term	(740.3)	(703.9)
	$ (584.8)	$ (561.5)

As at Dec. 31, 2005, there are income tax loss carryforwards of $37.5 million (2004 – $66.6 million) for which no tax benefit has been recognized. These losses begin to expire in 2013.

NOTE
17. EMPLOYEE FUTURE BENEFITS

A. Description

The corporation has registered pension plans in Canada and the United States covering substantially all employees of the corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options and in Canada, there is an additional supplemental defined benefit plan for Canadian-based defined contribution members whose annual earnings exceed the Canadian income tax limit. The defined benefit option of the registered pension plans has been closed for new employees for all periods presented.

The latest actuarial valuations of the registered and supplemental pension plans were as at Dec. 31, 2005. The measurement date used to determine plan assets and accrued benefit obligation was Dec. 31, 2005. The effective date of the next required valuation for funding purposes is Dec. 31, 2007. The supplemental pension plan is solely the obligation of the corporation. The corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The corporation has posted a letter of credit in the amount of $41.8 million to secure the obligations under the supplemental plan.

The corporation provides other health and dental benefits to the age of 65 for both disabled members (other post-employment benefits) and retired members (other post-retirement benefits). The latest actuarial valuation of these other plans was as at Dec. 31, 2004. The measurement date used to determine the accrued benefit obligation was also Dec. 31, 2005. The effective date of the next required valuation for funding purposes is Dec. 31, 2007.

B. Costs Recognized

Year ended Dec. 31, 2005	Registered	Supplemental	Other	Total
Current service cost	$ 4.2	$ 1.1	$ 1.3	$ 6.6
Interest cost	20.4	2.0	1.2	23.6
Actual return on plan assets	(43.9)	–	–	(43.9)
Actuarial (gains) losses in 2005	26.3	4.6	0.9	31.8
Past service cost in 2005	0.5	(1.2)	–	(0.7)
Difference between expected return and actual return on plan assets	19.8	–	–	19.8
Difference between actuarial (gain) loss recognized for the year and actual actuarial (gain) loss on accrued benefit obligation for the year	(23.9)	(4.3)	(0.6)	(28.8)
Difference between amortization of past service costs for the year and actual plan amendments for the year	(0.4)	1.2	0.3	1.1
Amortization of net transition obligation (asset)	(9.2)	0.3	–	(8.9)
Defined benefit (income) cost	(6.2)	3.7	3.1	0.6
Defined contribution option expense of registered pension plan	11.5	–	–	11.5
Net expense	$ 5.3	$ 3.7	$ 3.1	$ 12.1

Year ended Dec. 31, 2004	Registered	Supplemental	Other	Total
Current service cost	$ 4.2	$ 1.1	$ 0.6	$ 5.9
Interest cost	20.5	2.1	1.0	23.6
Actual return on plan assets	(33.4)	–	–	(33.4)
Actuarial (gains) losses in 2004	14.4	(1.5)	0.2	13.1
Plan amendments in 2004	–	–	3.8	3.8
Difference between expected return and actual return on plan assets	9.6	–	–	9.6
Difference between actuarial (gain) loss recognized for the year and actual actuarial (gain) loss on accrued benefit obligation for the year	(12.3)	2.0	0.3	(10.0)
Difference between amortization of past service costs for the year and actual plan amendments for the year	0.1	(0.1)	(3.8)	(3.8)
Amortization of net transition obligation (asset)	(9.2)	0.3	–	(8.9)
Defined benefit (income) cost	(6.1)	3.9	2.1	(0.1)
Defined contribution option expense of registered pension plan	10.4	–	–	10.4
Net expense	$ 4.3	$ 3.9	$ 2.1	$ 10.3

Year ended Dec. 31, 2003	Registered	Supplemental	Other	Total
Current service cost	$ 3.8	$ 1.4	$ 0.6	$ 5.8
Interest cost	21.0	2.2	1.1	24.3
Actual return on plan assets	(35.9)	–	–	(35.9)
Actuarial (gains) losses in 2003	21.5	(0.7)	0.5	21.3
Difference between expected return and actual return on plan assets	12.3	–	–	12.3
Difference between actuarial (gain) loss recognized for the year and actual actuarial (gain) loss on accrued benefit obligation for the year	(20.2)	1.3	(0.1)	(19.0)
Difference between amortization of past service costs for the year and actual plan amendments for the year	0.1	(0.1)	–	–
Amortization of net transition obligation (asset)	(9.1)	0.3	–	(8.8)
Defined benefit (income) cost	(6.5)	4.4	2.1	–
Defined contribution option expense of registered pension plan	9.7	–	–	9.7
Net expense	$ 3.2	$ 4.4	$ 2.1	$ 9.7

In 2005, 2004 and 2003, the entire net expense related to continuing operations.

C. Status of Plans

Year ended Dec. 31, 2005	Registered	Supplemental	Other
Fair value of plan assets	**$ 369.5**	**$ 1.7**	**$ –**
Accrued benefit obligation	**402.8**	**41.2**	**23.4**
Funded status – plan deficit	**(33.3)**	**(39.5)**	**(23.4)**
Amounts not yet recognized in financial statements:			
Unrecognized past service costs	**1.0**	**(1.6)**	**3.5**
Unamortized transition (asset) obligation	**(45.8)**	**2.6**	**–**
Unamortized net actuarial gains	**60.9**	**10.7**	**6.6**
Total recognized in financial statements:			
Accrued benefit liability	**$ (17.2)**	**$ (27.8)**	**$ (13.3)**
Amortization period in years (EARSL)	**8**	**8**	**15**

Year ended Dec. 31, 2004	Registered	Supplemental	Other
Fair value of plan assets	$ 352.0	$ 1.4	$ –
Accrued benefit obligation	379.0	36.6	21.7
Funded status – plan deficit	(27.0)	(35.2)	(21.7)
Amounts not yet recognized in financial statements:			
Unrecognized past service costs	0.5	(0.5)	3.8
Unamortized transition (asset) obligation	(55.0)	3.0	–
Unamortized net actuarial gains	57.1	6.6	6.2
Total recognized in financial statements:			
Accrued benefit liability	$ (24.4)	$ (26.1)	$ (11.7)
Amortization period in years (EARSL)	9	9	11

The current portion of the accrued benefit liability is included in accounts payable and accrued liabilities on the consolidated balance sheets. The long-term portion is included in deferred credits and other long-term liabilities.

Year ended Dec. 31, 2005	Registered	Supplemental	Other
Accrued current liabilities	**$ 7.2**	**$ 0.5**	**$ 1.3**
Other long-term liabilities	**10.0**	**27.3**	**12.0**
Accrued benefit liability	**$ 17.2**	**$ 27.8**	**$ 13.3**

Year ended Dec. 31, 2004	Registered	Supplemental	Other
Accrued current liabilities	$ 2.2	$ 0.7	$ 1.1
Other long-term liabilities	22.2	25.4	10.6
Accrued benefit liability	$ 24.4	$ 26.1	$ 11.7

D. Contributions

Expected cash flows are as follows:

	Registered	Supplemental	Other	Total
Employer contributions				
2006 (expected)	$ 11.1	$ 0.5	$ 0.3	$ 11.9
Expected benefit payments				
2006	24.0	1.7	1.3	27.0
2007	24.4	2.0	1.5	27.9
2008	25.1	2.0	1.6	28.7
2009	26.0	2.1	1.7	29.8
2010	26.4	2.3	1.8	30.5
2011 – 2015	141.6	12.9	10.0	164.5

E. Plan Assets

	Registered	Supplemental	Other
Fair value of plan assets at Dec. 31, 2003	$ 351.9	$ 0.9	$ –
Contributions	2.6	0.5	0.1
Transfers to defined contribution option	(9.0)	–	–
Benefits paid	(25.3)	–	(0.1)
Effect of translation on U.S. plans	(1.6)	–	–
Actual return on plan assets[1]	33.4	–	–
Fair value of plan assets at Dec. 31, 2004	$ 352.0	$ 1.4	$ –
Contributions	2.1	0.5	0.3
Transfers	0.1	–	–
Benefits paid	(27.7)	(0.1)	(0.3)
Effect of translation on U.S. plans	(1.0)	–	–
Actual return on plan assets[1]	43.9	–	–
Fair value of plan assets at Dec. 31, 2005	**$ 369.4**	**$ 1.8**	**$ –**

1 Net of expenses.

The corporation's investment policy is to achieve a consistently high investment return over time while maintaining an acceptable level of risk to satisfy the benefit obligations of the pension plans. The goal is to maintain a long-term rate of return on the fund that at least equals the growth of liabilities, currently 7 per cent. The pension fund may be invested in publicly traded common or preferred equity shares, rights or warrants; convertible debentures or preferred securities; bonds, debentures, mortgages, notes or other debt instruments of government agencies or corporations; private company securities; guaranteed investment contracts; term deposits; cash or money market securities; and mutual or pooled funds eligible for pension fund investment. The target allocation percentages are 60 per cent equity and 40 per cent fixed income. Cash and money market instruments may be held from time to time as short-term investment decisions or as defensive reserves within the portfolios of each asset class. The fund may invest in derivatives for the purpose of hedging the portfolio or altering the desired mix of the fund. Derivative transactions that leverage the fund in any way are not permitted without the specific approval of the Pension Committee.

The allocation of plan assets by major asset category at Dec. 31, 2005 and 2004 is as follows:

Year ended Dec. 31, 2005	Registered	Supplemental
Equity securities	**62.8%**	**–**
Debt securities	**36.7%**	**–**
Cash equivalents	**0.5%**	**100.0%**
Total	**100.0%**	**100.0%**

Year ended Dec. 31, 2004	Registered	Supplemental
Equity securities	55.9%	–
Debt securities	42.5%	–
Cash equivalents	1.6%	100.0%
Total	100.0%	100.0%

Plan assets include common shares of the corporation having a fair value of $1.0 million at Dec. 31, 2005 (2004 – $0.7 million). The corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2005 (2004 – $0.1 million).

F. Reconciliation of Accrued Benefit Obligations

	Registered	Supplemental	Other
Accrued benefit obligation as at Dec. 31, 2003	$ 366.6	$ 36.5	$ 18.0
Current service cost	4.2	1.1	0.6
Interest cost	20.5	2.1	1.0
Expected benefits paid	(23.7)	(1.6)	(1.2)
Past service charge	–	–	3.8
Effect of translation on U.S. plans	(3.0)	–	(0.7)
Actuarial loss (gain)	14.4	(1.5)	0.2
Accrued benefit obligation as at Dec. 31, 2004	$ 379.0	$ 36.6	$ 21.7
Current service cost	4.2	1.1	1.3
Interest cost	20.4	2.0	1.2
Expected benefits paid	(25.7)	(1.8)	(1.2)
Past service charge	0.5	(1.2)	–
Effect of translation on U.S. plans	(2.0)	–	(0.5)
Actuarial loss (gain)	26.3	4.6	0.9
Accrued benefit obligation as at Dec. 31, 2005	**$ 402.7**	**$ 41.3**	**$ 23.4**

G. Assumptions

The significant actuarial assumptions adopted in measuring the corporation's accrued benefit obligations were as follows:

Year ended Dec. 31, 2005	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate	**5.0%**	**5.0%**	**5.2%**
Rate of compensation increase	**3.5%**	**3.5%**	**–**
Benefit cost for year ended Dec. 31			
Discount rate	**5.5%**	**5.5%**	**5.6%**
Rate of compensation increase	**3.5%**	**3.5%**	**–**
Expected rate of return on plan assets	**7.1%**	**–**	**–**
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation	**–**	**–**	**9.5%–11.5%**[1]
Dental care cost escalation	**–**	**–**	**4.0%**
Provincial health care premium escalation	**–**	**–**	**2.5%**

Year ended Dec. 31, 2004	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate	5.5%	5.5%	5.6%
Rate of compensation increase	3.5%	3.5%	–
Benefit cost for year ended Dec. 31			
Discount rate	5.8%	5.8%	5.9%
Rate of compensation increase	3.5%	3.5%	–
Expected rate of return on plan assets	7.1%	–	–
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation		–	10.0%–12.5%[1]
Dental care cost escalation			4.0%
Provincial health care premium escalation			2.5%

1 Decreasing gradually to 5.0 per cent by 2015 for Canadian plans and by 2012 for U.S. plans and remaining at that level thereafter.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. The estimated rate of return is lower than the historical returns of the appropriate indices.

Sensitivity to changes in assumed health care cost trend rates are as follows:

	One percentage point increase	One percentage point decrease
Effect on total service and interest costs	$ 0.2	$ (0.2)
Effect on post-retirement benefit obligation	$ 1.3	$ (1.2)

NOTE 18. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES

A. Foreign Exchange Rate Risk Management

I. Hedges of Foreign Operations

The corporation has exposure to changes in the carrying values of its self-sustaining foreign operations as a result of changes in foreign exchange rates. The corporation uses cross-currency interest rate swaps at fixed and floating rate terms, forward sales contracts and direct foreign currency debt to hedge these exposures. The principal component of the cross-currency interest rate swaps and direct foreign currency debt hedge a portion of the carrying value of foreign operations. Translation gains and losses related to these components are deferred and included in CTA in shareholders' equity on a net of tax basis.

Realized gains and losses arising from the hedging of net investments and inter-company transactions are reflected as an investing activity in the statement of cash flows. Upon the settlement of certain financial instruments designated as net investment hedges, a foreign exchange gain of $89.8 million was realized in 2005 (2004 – $47.8 million, 2003 – $194.1 million). This is recorded in the corporation's cumulative translation account in total equity. During 2004, the corporation reclassified prior year cash flows to be consistent with the current presentation.

Details of the notional amounts of cross-currency interest rate swaps are as follows:

Year ended Dec. 31	2005			2004		
	Amount	Fair value	Maturities	Amount	Fair value	Maturities
Australian dollars	**AUD$34.0**	**$ 0.8**	**2009**	AUD$34.0	$ (3.4)	2005
U.S. dollars	**US$752.1**	**$ 101.9**	**2007–2015**	US$706.9	$ 128.7	2005–2012

In addition, the corporation has designated U.S. dollar denominated long-term debt *(Note 10)* in the amount of US$694.0 million (2004 – US$727.9 million) as a hedge of its net investment in the United States and Mexico operations with $177.0 million of related foreign currency losses (2004 – $125.8 million loss) deferred and included in CTA.

The corporation has also hedged a portion of its net investment in self-sustaining subsidiaries with foreign currency forward sales contracts as shown below:

Year ended Dec. 31	2005			2004		
	Amount	Fair value	Maturities	Amount	Fair value	Maturities
New Zealand dollars	**NZ$–**	**$ –**	**–**	NZ$513.3	$ (142.5)	2005
U.S. dollars	**US$339.9**	**$ 15.8**	**2006–2008**	US$499.5	$ 82.10	2005
Australian dollars	**AUD$22.8**	**$ (0.1)**	**2006**	AUD$8.6	$ –	2005
Mexican pesos	**MXN 871.6**	**$ (11.9)**	**2009**	MXN 871.6	$ 10.8	2009

In addition, the corporation has hedged foreign currency denominated inter-company loans to self-sustaining foreign subsidiary using forward contracts with a notional amount of US$49.2 million (2004 – US$145.2 million) and a net fair value liability of $0.7 million (2004 – $78.2 million).

At Dec. 31, 2005, a $101.9 million asset (2004 – $231.5 million) and a $14.7 million liability (2004 – $83.9 million) related to the cross-currency interest rate swaps and forward sales contracts was recorded in other assets *(Note 8)* and deferred credits and other long-term liabilities *(Note 11)*, respectively.

II. Hedges of Future Foreign Currency Obligations

The corporation has hedged future foreign currency obligations through forward purchase contracts as follows:

Year ended Dec. 31	2005					2004			
Currency sold	Amount sold	Currency purchased	Amount purchased	Fair value asset (liability)	Maturities	Amount sold	Amount purchased	Fair value asset (liability)	Maturities
Canadian dollars	**$7.8**	**US$**	**US$6.6**	**$ (0.2)**	**2006**	$43	US$29.5	$ (6.8)	2005
U.S. dollars	**$71.4**	**Cdn$**	**$83.0**	**$ 0.4**	**2006**	US$24.5	$37.3	$ 7.1	2005
Mexican pesos	**MXN 160.7**	**US$**	**US$15.1**	**$ 0.1**	**2006**	MXN 51.6	US$4.6	$ 0.1	2005
Canadian dollars	**–**	**NZ$**	**NZ$ –**	**$ –**	**N/A**	$17.8	NZ$20.0	$ (0.5)	2005
U.S. dollars	**–**	**NZ$**	**NZ$ –**	**$ –**	**N/A**	US$207.1	NZ$456.7	$ 141.1	2005

At Dec. 31, 2005, a $25.6 million asset (2004 – $8.7 million) and a $25.2 million liability (2004 – $52.2 million) related to these hedges was recorded in other assets *(Note 8)* and deferred credits and other long-term liabilities *(Note 11)*, respectively.

B. Interest Rate Risk Management

I. Existing Debt

The corporation has converted fixed interest rate debt at fixed rates, ranging from 5.75 per cent to 6.9 per cent, to floating rates through interest rate swaps *(Note 10)* as shown below:

Year ended Dec. 31	2005			2004		
	Notional amount	Fair value of swaps	Maturities	Notional amount	Fair value of swaps	Maturities
Fixed rate debt	**$ 375.0**	**$ 30.8**	**2006–2011**	$ 375.0	$ 39.9	2006–2011
	US$300.0	**$ (4.8)**	**2013**	US$300.0	$ 1.60	2013

The corporation has converted debt at floating interest rates to a fixed rate of 7.2 per cent through interest rate swaps *(Note 10)* as shown below:

Year ended Dec. 31	2005			2004		
	Notional amount	Fair value of swaps	Maturity	Notional amount	Fair value of swaps	Maturity
						(Restated, Note 1)
Floating rate debt	**US$37.1**	**$ (1.3)**	**2008**	US$50.3	$ (3.9)	2008

Including the interest rate swap above, 28.9 per cent of the corporation's debt is subject to floating interest rates (2004 – 23.9 per cent).

The fair value of the corporation's fixed interest long-term debt changes as interest rates change, with details as follows:

Year ended Dec. 31	2005		2004	
	Carrying amount	Fair value	Carrying amount	Fair value
				(Restated, Note 1)
Long-term debt, including current portion	**$ 2,780.0**	**$ 2,905.0**	$ 3,076.2	$ 3,259.9

At Dec. 31, 2005, a $38.4 million asset (2004 – $44.4 million) related to the interest rate swaps was recorded in other assets *(Note 8)*.

C. Energy Commodities Price Risk Management

I. Trading Activities

The corporation markets energy derivatives, including physical and financial swaps, forwards and options, to optimize returns from assets, to earn trading revenues and to gain market information.

At Dec. 31, 2005 and 2004, details of the corporation's fixed price trading positions were as follows:

Units (000s)	Electricity (MWh)	Natural gas (GJ)
Fixed price payor, notional amounts, Dec. 31, 2005	**19,315**	**11,126**
Fixed price payor, notional amounts, Dec. 31, 2004	14,029	13,422
Fixed price receiver, notional amounts, Dec. 31, 2005	**19,047**	**12,158**
Fixed price receiver, notional amounts, Dec. 31, 2004	13,558	12,277
Maximum term in months, Dec. 31, 2005	**24**	**12**
Maximum term in months, Dec. 31, 2004	24	12

The gross physical and financial volumes of settled sales of proprietary trading transactions are as follows:

Electricity (GWh) Year ended Dec. 31	2005	2004	2003
Physical	**58,016**	61,165	55,506
Financial	**57,666**	23,239	34,327
	115,682	84,404	89,833

Gas (million GJ) Year ended Dec. 31	2005	2004	2003
Physical	**86.9**	122.4	100.1
Financial	**326.9**	308.0	170.1
	413.8	430.4	270.2

The carrying and fair value of energy commodity trading assets and liabilities included on the balance sheets are as follows:

Dec. 31	2005	2004
Price risk management assets		
Current	**$ 63.8**	$ 41.9
Long term	**13.8**	11.3
Price risk management liabilities		
Current	**(58.3)**	(27.7)
Long term	**(8.6)**	(10.0)
Net price risk management assets outstanding	**$ 10.7**	$ 15.5

The change in fair value of contracts outstanding at Dec. 31, 2005 and 2004, as well as the changes in fair value of the net price risk management assets for 2005, is attributed to the following:

Change in fair value of net assets	Fair value
Net price risk management assets outstanding at Dec. 31, 2004	$ 15.5
Contracts realized, amortized or settled during the year	(24.4)
Changes in values attributable to market price and other market changes	6.1
New contracts entered into during the current calendar year	13.5
Net price risk management assets outstanding at Dec. 31, 2005	**$ 10.7**

II. Hedging Activities

The corporation uses energy derivatives, including physical and financial swaps, forwards and options, to manage its exposure to changes in electricity and natural gas prices. At Dec. 31, 2005, details of the corporation's hedging position were as follows:

	Fixed price payor notional amount (GJ)	Fixed price receiver notional amount (MWh)	Maximum term in months
Commodity hedges (000s)	8,093.7	33,770.7	60

The fair value of these hedges is a $382.6 million liability (2004 – $12.6 million).

In addition, the corporation has entered into a number of long-term power sales and gas purchase contracts, as well as transportation agreements in the normal course of business. The maximum remaining term of these contracts is 20 years.

D. Credit Risk Management

The corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures. For Energy Marketing, the corporation sets strict credit limits for each counterparty and halts trading activities with the counterparty if the limits are exceeded. The corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees and/or letters of credit to support the ultimate collection of these receivables. TransAlta is exposed to minimal credit risk for Alberta Generation PPAs as all receivables are guaranteed by letters of credit.

The maximum credit exposure to any one customer, excluding the California market receivables discussed above and including the fair value of open trading positions, is $34.2 million.

NOTE 19. JOINT VENTURES

Joint ventures at Dec. 31, 2005 included the following:

Joint venture	Ownership interest	Description
Sheerness joint venture	50%	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, and is operated by Canadian Utilities
Meridian joint venture	50%	Cogeneration plant in Alberta, of which TA Cogen has a 50 per cent interest, and is operated by Husky Energy
Fort Saskatchewan joint venture	60%	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, and is operated by TransAlta
McBride Lake joint venture	50%	Wind generation facilities in Alberta, operated by TransAlta
Goldfields Power joint venture	50%	Gas-fired plant in Australia, operated by TransAlta
CE Generation LLC	50%	Geothermal and gas plants in the United States, operated by CE Gen affiliates
Genesee 3	50%	Coal-fired plant in Alberta, operated by EPCOR Utilities Inc.

Summarized information on the results of operations, financial position and cash flows relating to the corporation's pro-rata interests in its jointly controlled corporations was as follows:

	2005	2004	2003
Results of operations			
Revenues	$ **619.9**	$ 505.2	$ 539.0
Expenses	**(481.1)**	(424.3)	(429.3)
Non-controlling interests	**(43.7)**	(37.1)	(25.9)
Proportionate share of net earnings	$ **95.1**	$ 43.8	$ 83.8
Cash flows			
Cash flow from operations	$ **111.5**	$ 153.2	$ 498.7
Cash flow used in investing activities	**(10.3)**	(21.6)	(1,603.4)
Cash flow used in financing activities	**(76.3)**	(129.1)	1,131.5
Proportionate share of decrease in cash and cash equivalents	$ **24.9**	$ 2.5	$ 26.8
Financial position			
Current assets	$ **162.5**	$ 112.7	$ 125.9
Long-term assets	**1,895.4**	2,033.7	2,214.4
Current liabilities	**(118.0)**	(110.9)	(135.1)
Long-term liabilities	**(552.7)**	(635.6)	(806.2)
Non-controlling interests	**(396.1)**	(416.3)	(164.5)
Proportionate share of net assets	$ **991.1**	$ 983.6	$ 1,234.5

NOTE
20. RELATED-PARTY TRANSACTIONS

On March 8, 2005, TA Cogen entered into an agreement with TEC whereby TEC provided a financial fixed-for-floating price swap to TA Cogen during planned maintenance at Sheerness in the second quarter of 2005.

On Dec. 1, 2004, TransAlta completed the sale of its 50 per cent interest in the 220 MW Meridian Cogeneration Facility located in Lloydminster, Saskatchewan to TA Cogen for its fair value of $110.0 million. TA Cogen (owned 50.01 per cent by TransAlta and 49.99 per cent by TransAlta Power) financed the acquisition through the use of $50.0 million of cash on hand and by the issuance of $30.0 million of units to each of TransAlta Power and TEC. TA Cogen also issued an advance to TEC for $30.0 million. The advance outstanding at Dec. 31, 2005 was $5.0 million (2004 – $28.0 million) and is included in accounts receivable. TransAlta recorded a gain of $11.5 million after-tax or $0.06 per common share ($17.7 million pre-tax) in 2004.

On July 31, 2003, TransAlta completed the sale of its 50 per cent interest in the two-unit coal-fired Sheerness Generating Station to TA Cogen for $630.0 million. The exchange amount was at fair value and was determined based on an estimate of the future net cash flows of the plant and approved by the independent directors of TA Cogen. There are no ongoing contractual commitments or arrangements resulting from this sale apart from the provision of operational and management services under normal commercial terms for the Sheerness Generating Station.

In connection with the sale of the Sheerness Generating Station, the obligation for TransAlta to purchase all of TransAlta Power's interest in TA Cogen on Dec. 31, 2018 that arose on the sale of power generation assets to TA Cogen in 1998 has been eliminated; therefore the deferred gain of $119.8 million related to this sale was recognized in earnings in 2003. In addition, the management agreements between TransAlta, TransAlta Power and TA Cogen were amended to remove the mechanism for the deferral of management fees and remove the obligation for TransAlta Power and TA Cogen to pay management fees to TransAlta in the future. As consideration for the amendments, TransAlta received $1.0 million from TransAlta Power and $5.0 million from TA Cogen.

In February 2003, TransAlta entered into an agreement with CE Gen, a corporation jointly controlled by TransAlta and MidAmerican Energy Holdings Company, a subsidiary of Berkshire Hathaway, whereby TransAlta buys available power from certain CE Gen subsidiaries under normal commercial terms. In addition, CE Gen has entered into contracts with related parties to provide administrative and maintenance services.

For the period November 2002 to November 2007, TA Cogen entered into a transportation swap transaction with a wholly-owned subsidiary of TransAlta, TEC *(Note 8)*. TEC operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TEC also provides management services to the Sheerness Generating Station in Alberta, which is operated by Canadian Utilities. The business purpose of the transportation swap was to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline trans-

portation for two of its plants over the period of the swap. This stabilizes cash distributions in TA Cogen and thereby preserves the value of the limited partnership as a financing vehicle of TransAlta. The notional gas volume in the transaction was the total delivered fuel for both facilities. Exchange amounts are based on the market value of the contract. TransAlta entered into an offsetting contract with an external third party, therefore TransAlta has no risk other than counterparty risk.

TA Cogen entered into a fixed-for-floating gas swap transaction with TEC for a 61-month period starting Dec. 1, 2000. The swap transaction provides TA Cogen with fixed price gas for both the Mississauga and Ottawa plants over the period. The floating prices associated with the Mississauga and Ottawa cogeneration plants' long-term fuel supply agreements were transferred to TEC's account. The notional gas volume in the transaction was the total delivered fuel for both facilities. As consideration and in negotiation, TA Cogen transferred the right to incremental revenues associated with curtailed electrical production and subsequent higher revenue gas sales. At Dec. 31, 2005, the portion of the contract related to the non-controlling interest had a fair value liability of $1.6 million (2004 – $4.9 million).

NOTE
21. COMMITMENTS

A significant portion of the corporation's electricity and thermal sales revenues are subject to PPAs and long-term contracts. Commencing Jan. 1, 2001, a large portion of Alberta's coal generation assets became subject to long-term PPAs for a period approximating the remaining life of each plant or unit. These PPAs set a production requirement and availability target for each plant or unit and the price at which each MWh will be supplied to the customer. Remaining coal capacity in Alberta is sold on the open electricity market. A portion of Poplar Creek's gas-fired capacity and all of its steam is committed to the customer under a long-term contract. The remaining capacity may be taken by the customer at specified rates or sold on the open electricity market by TransAlta. Other gas-fired facilities in Alberta supply steam and/or electricity to specified customers under long-term contracts with additional requirements for availability, reliability and other plant-specific performance measures. For Mexico, the plants' energy production is subject to 25-year contracts with the Comisión Federal de Electricidad. These contracts set availability targets and the price at which the plant will be paid per kilowatt of available capacity, as well as plant efficiency targets for recovery of fuel costs based on market prices. At Sarnia, there are 20-year contracts with a customer group with three, five-year options for extensions to the contracts. The contracts allow for up to 40 per cent of the plant's maximum capacity. These contracts set payments for peak megawatts, total megawatt hours and steam consumed, while TransAlta assumes the availability and heat rate risk. The remaining capacity is available for export to the merchant market, based on market conditions. Energy production at the remaining Ontario plants is subject to contracts expiring in seven to 12 years. The Ontario plants, except Ottawa, have contracts that set availability targets and the price at which the plant will be paid per MWhs produced, as well as risk sharing of fuel costs based on market prices. The terms of the Ottawa plant for electricity are similar to the other Ontario plants except the risk sharing of fuel costs. Thermal energy contracts for these Ontario plants expire at the same time as the energy production contracts and are with a different customer base. These contracts set payments for volumes consumed, while TA Cogen assumes the heat rate risk. At Centralia, a significant portion of production is subject to short- to medium-term energy sales contracts. In addition, a portion of the corporation's energy sales from its gas plants are subject to medium- to long-term energy sales contracts.

The corporation has entered into a number of long-term gas purchase agreements, transportation and transmission agreements, royalty and right-of-way agreements in the normal course of operations. Approximate future payments under the fixed price purchase contracts, operating lease and mining agreements are as follows:

	Fixed price gas purchase contracts	Operating leases	Mining agreements	Total
2006	$ 55.8	$ 12.8	$ 61.6	$ 130.2
2007	56.5	11.3	44.9	112.7
2008	58.3	10.3	34.1	102.7
2009	35.2	9.6	20.1	64.9
2010	13.4	9.3	19.9	42.6
2011 and thereafter	127.0	86.6	297.7	511.3
Total	$ 346.2	$ 139.9	$ 478.3	$ 964.4

NOTE
22. OTHER CONTINGENCIES

In March 2003, FERC completed its investigation of natural gas and power markets and indicated that the total industry refunds for price overcharges will be higher than originally anticipated.

In June 2003, FERC issued two show cause orders, the Partnership Gaming Order and the Gaming Practices Order, in which TransAlta's U.S. subsidiaries were named. These orders required TransAlta to justify certain trading activities in California between Oct. 1, 2000 and June 20, 2001. In response to FERC's show cause orders, TransAlta confirmed that it did not engage in gaming behavior. Based on the information provided by TransAlta, FERC Trial Staff filed a Motion to Dismiss with respect to TransAlta in the two show cause proceedings. On Jan. 22, 2004, FERC granted the FERC Trial Staff's motion to dismiss TransAlta from both the Partnership Gaming Order and the Gaming Practices Order. FERC found that TransAlta did not engage in prohibited gaming practices.

On May 30, 2002, the California Attorney General's Office filed civil complaints in the state court of California against eight wholesale power companies, including TransAlta. The complaint alleges violations of California's unfair business practices law in connection with rates charged for wholesale electricity sales. The state court denied the Attorney General's complaint and granted an order to dismiss the claims against TransAlta. The Attorney General dropped its appeal of this decision on Nov. 2, 2004, as such the decision is final as of such date.

On Dec. 16, 2002, the Canadian government ratified the Kyoto Protocol, which came into effect on Feb. 16, 2005. The Kyoto Protocol is not expected to have an impact on TransAlta's U.S., Mexican or Australian operations. TransAlta is not able to estimate the full impact the Protocol will have on its Canadian operations, as the Canadian government has not yet established its regulatory requirements. However, the PPAs for TransAlta's coal-fired plants in Alberta contain 'Change of Law' provisions that should provide an opportunity to recover compliance costs from the PPA customers.

Mercury control requirements are being drafted in Canada and the United States and will impact coal-fired generation plants. In Alberta, TransAlta anticipates its coal-fired plants will require some form of mercury capture technology in the next five to seven years. The exact technology and performance requirements have not yet been finalized, however, TransAlta is maintaining engineering readiness. Our PPAs will also provide an opportunity to recover these costs under 'Change of Law' provisions. In the United States, TransAlta's Centralia coal-fired plant may or may not be subject to mercury reduction requirements by 2010, depending on Washington State determinations which are expected by the end of 2006.

The corporation is involved in various other claims and legal actions arising from the normal course of business. The corporation does not expect that the outcome of these proceedings, having regard to insurance available to it and the amounts reserved in respect of such claims, will have a materially adverse effect on the corporation as a whole.

NOTE
23. COMPARATIVE FIGURES

Certain of the comparative figures have been reclassified to conform with the current year's presentation. Such reclassification did not impact previously reported net income or retained earnings.

NOTE
24. SUBSEQUENT EVENTS

On Feb. 15, 2006, the corporation announced the signing of a five-year agreement with the Ontario Power Authority (OPA) for its Sarnia Regional Cogeneration Power Plant. Under the terms of the agreement, TransAlta will be available to supply an average of 400 MW of electricity to the Ontario market. The supply agreement is effective from Jan. 1, 2006 to Dec. 31, 2010.

NOTE
25. UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP, which, in most respects, conform to U.S. GAAP. Significant differences between Canadian and U.S. GAAP are as follows:

A. Earnings and Earnings Per Share (EPS)

Year ended Dec. 31	Reconciling items	2005	2004	2003
			(Restated, Note 1)	(Restated, Note 1)
Earnings from continuing operations – Canadian GAAP		**$ 186.8**	$ 160.6	$ 234.2
Derivatives and hedging activities, net of tax	I	**10.5**	(3.8)	(4.5)
Start-up costs, net of tax	III	**(0.1)**	(0.1)	(6.7)
Recognition of debt extinguishment, net of tax	IV	**–**	–	11.1
Amortization of pension transition adjustment	II	**(4.0)**	(4.5)	(4.6)
Cumulative effect of change in accounting principle, net of tax	X	**–**	–	52.5
Earnings from continuing operations – U.S. GAAP		**193.2**	152.2	282.0
Earnings from discontinued operations – Canadian and U.S. GAAP		**12.0**	9.6	–
Net earnings before change in accounting principle – U.S. GAAP		**205.2**	161.8	282.0
Net earnings – U.S. GAAP		**$ 205.2**	$ 161.8	$ 282.0
Foreign currency cumulative translation adjustment	I,VII	**(22.6)**	3.7	8.2
Net gain (loss) on derivative instruments	I,VII	**(214.6)**	10.4	8.8
Registered pension alternate minimum liability	II,VII	**(11.5)**	(0.6)	0.6
Comprehensive income – U.S. GAAP		**$ (43.5)**	$ 175.3	$ 299.6
Basic EPS – U.S. GAAP				
Earnings from continuing operations		**$ 0.98**	$ 0.79	$ 1.24
Earnings from discontinued operations		**0.06**	0.05	–
Cumulative effect of change in accounting principle		**–**	–	0.28
Net earnings		**$ 1.04**	$ 0.84	$ 1.52
Diluted EPS – U.S. GAAP				
Earnings from continuing operations		**$ 0.98**	$ 0.79	$ 1.24
Earnings from discontinued operations		**0.06**	0.05	–
Cumulative effect of change in accounting principle		**–**	–	0.28
Net earnings		**$ 1.04**	$ 0.84	$ 1.52

B. Balance Sheet Information

Dec. 31		2005		2004	
	Reconciling items	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP[1]
Assets					
Price risk management assets, current	I	**63.8**	**77.7**	41.9	89.7
Accounts receivable	VIII	**593.4**	**593.4**	422.5	421.0
Income taxes receivable	I	**48.8**	**50.2**	60.1	75.1
Property, plant and equipment, net	II	**5,545.5**	**5,542.4**	5,702.6	5,680.7
Price risk management assets, long term	I	**13.8**	**162.6**	11.3	199.0
Other assets (including current portion)	I, II	**210.9**	**46.2**	500.7	298.8
Liabilities					
Accounts payable and accrued liabilities	V	**590.3**	**587.5**	442.6	367.7
Income taxes payable	II	**13.8**	**8.4**	6.1	0.7
Price risk management liabilities, current	I	**58.3**	**229.7**	27.7	59.9
Long-term debt	I	**2,208.6**	**2,237.0**	2,321.1	2,365.0
Deferred credits and other liabilities (including current portion)	I	**365.9**	**365.9**	633.0	639.8
Price risk management liabilities, long term	I	**8.6**	**259.3**	10.0	58.6
Future or deferred income tax liabilities (including current portion)	I, II, IV, V	**758.5**	**609.9**	715.0	705.9
Non-controlling interest	I	**558.6**	**557.9**	616.4	615.4
Equity					
Contributed surplus	X	**–**	**133.0**	–	133.0
Retained earnings	I, II, V	**912.2**	**756.8**	910.3	771.0
Cumulative translation adjustment	I	**(67.0)**	**–**	(52.2)	–
Accumulated other comprehensive income	I, V, VII	**–**	**(341.3)**	–	(92.6)

1 Restated, reconciling items X and XI

C. Reconciling Items

I. Derivatives and Hedging Activities

Under U.S. GAAP, trading and non-trading activities are accounted for in accordance with Statement 133, which requires that derivative instruments be recorded in the consolidated balance sheets at fair value as either assets or liabilities, and that changes in fair value be recognized currently in earnings, unless specific hedge accounting criteria are met. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized currently in earnings. If the derivative is designated as a cash flow hedge, the changes in the fair value of the derivative are recorded in other comprehensive income, and the gains and losses related to these derivatives are recognized in earnings in the same period as the settlement of the underlying hedged transaction. Any ineffectiveness relating to these hedges is recognized currently in earnings. The assets and liabilities related to derivative instruments for which hedge accounting criteria are met are reflected as price risk management assets and liabilities in the consolidated balance sheets. Many of the corporation's electricity sales and fuel supply agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment. This exemption is available for the electricity industry as electricity cannot be stored and generators may be required to maintain sufficient capacity to meet customer demands. This exemption is also available for some physically settled commodity contracts if certain criteria are met. Non-derivatives used in trading activities are accounted for using the accrual method under U.S. GAAP.

i. Fair Value Hedging Strategy

The corporation enters into forward exchange contracts to hedge certain firm commitments denominated in foreign currencies to protect against adverse changes in exchange rates and uses interest rate swaps to manage interest rate exposure. The swaps modify exposure to interest rate risk by converting a portion of the corporation's fixed-rate debt to a floating rate.

There was no ineffectiveness related to these hedges in the periods presented.

ii. Cash Flow Hedging Strategy

At Dec. 31, 2005, the corporation's cash flow hedges of the forecasted sale of power and the forecasted purchase of natural gas for the corporation's plants resulted in the recognition of an after tax unrealized loss in OCI of $241.7 million. These hedges have been accounted for on an accrual basis under Canadian GAAP but have been recorded on the balance sheet at fair value for U.S. GAAP.

In the year ended Dec. 31, 2005, the corporation's cash flow hedges resulted in an after-tax loss of $nil (2004 – $nil, 2003 – $1.9 million) related to the ineffective portion of its hedging instruments, and an after-tax gain of $nil for year ended Dec. 31, 2005 (2004 – $nil, 2003 – $2.0 million) related to the portion not designated as a hedge.

In November 2003, forward starting swaps with a notional amount of US$200.0 million and treasury and spread locks with a notional amount of $100.0 million were settled and debt was issued, resulting in an after-tax loss of $25.3 million. The loss is being reclassified from accumulated other comprehensive income (AOCI) into income as interest expense is recognized on the debt.

Over the next 12 months, the corporation estimates that $91.4 million of after-tax losses that arose from cash flow hedges will be reclassified from AOCI to net earnings. These estimates assume constant gas and power prices, interest rates and exchange rates over time; however, the actual amounts that will be reclassified will vary based on changes in these factors. Therefore, management is unable to predict what the actual reclassification from AOCI to earnings (positive or negative) will be for the next 12 months.

iii. Net Investment Hedges

The company uses cross-currency interest rate swaps, forward sales contracts and direct foreign currency debt to hedge its exposure to changes in the carrying value of its investments in its foreign subsidiaries in the United States, Australia and Mexico. Realized and unrealized gains and losses from these hedges are included in Other Comprehensive Income (OCI), with the related amounts due to or from counterparties included in long-term derivative assets and liabilities and long-term debt.

In the year ended Dec. 31, 2005, the corporation recognized an after-tax loss of $22.6 million (2004 – $3.7 million income, 2003 – $8.2 million income) on its net investment hedges, included in OCI.

In the year ended Dec. 31, 2005, the corporation recognized after-tax gains of $nil (2004 – nil, 2003 – $0.2 million), related to ineffectiveness of net investment hedges.

iv. Trading Activities

The corporation markets energy derivatives to optimize returns from assets, to earn trading revenues and to gain market information. Derivatives, as defined under Statement 133, are recorded on the consolidated balance sheets at fair value under both Canadian and U.S. GAAP. Non-derivative contracts entered into subsequent to the rescission of EITF 98-10 are accounted for using the accrual method.

v. Other Hedging Activities

In the year ended Dec. 31, 2005, the corporation recognized pre-tax losses of $13.7 million (2004 – $1.1 million, 2003 – $0.7 million gains) related to hedging activities that do not qualify for hedge accounting under Statement 133.

II. Employee Future Benefits

U.S. GAAP requires that the cost of employee pension benefits be determined using the accrual method with application from 1989. It was not feasible to apply this standard using this effective date. The transition asset as at Jan. 1, 1998 was determined in accordance with elected practice prescribed by the Securities and Exchange Commission (SEC) and is amortized over 10 years.

As a result of the corporation's plan asset return experience for its U.S. registered pension plan, at Dec. 31, 2005, the corporation was required under U.S. GAAP to recognize an additional minimum liability. The liability was recorded as a reduction in common equity through a charge to OCI, and did not affect net income for 2005. The charge to OCI, will be restored through common equity in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

III. Start-up Costs

Under U.S. GAAP, certain start-up costs, including revenues and expenses in the pre-operating period, are expensed rather than capitalized to deferred charges and property, plant and equipment as under Canadian GAAP, which also results in decreased depreciation and amortization expense under U.S. GAAP.

IV. Debt Extinguishment

Under U.S. GAAP, the premium on redemption of long-term debt related to the 1998 limited partnership transaction was recorded when incurred, whereas for Canadian GAAP, the loss was being amortized to earnings over the period of the limited partnership (20 years). As the buyback option was terminated in connection with the sale of the Sheerness plant, the deferred amount was recognized in earnings in 2003.

V. Income Taxes

Future income taxes under Canadian GAAP are referred to as deferred income taxes under U.S. GAAP.

Deferred income taxes under U.S. GAAP would be as follows:

Dec. 31	2005	2004
Future income tax liabilities (net) under Canadian GAAP	$ **(584.8)**	$ (561.5)
Derivatives	**160.0**	23.2
Start-up costs	**(2.3)**	(2.3)
Pensions	**(9.1)**	(11.8)
	$ **(436.2)**	$ (552.4)

Comprised of the following:

Dec. 31	2005	2004
Current deferred income tax assets	**$ 26.6**	$ 21.5
Long-term deferred income tax assets	**147.1**	132.0
Current deferred income tax liabilities	**(15.5)**	(11.1)
Long-term deferred income tax liabilities	**(594.4)**	(694.8)
	$ (436.2)	$ (552.4)

VI. Joint Ventures

In accordance with Canadian GAAP, joint ventures are required to be proportionately consolidated regardless of the legal form of the entity. Under U.S. GAAP, incorporated joint ventures are required to be accounted for by the equity method. However, in accordance with practices prescribed by the SEC, the corporation, as a Foreign Private Issuer, has elected for the purpose of this reconciliation to account for incorporated joint ventures by the proportionate consolidation method.

VII. Other Comprehensive Income (Loss)

The changes in the components of OCI were as follows:

Year ended Dec. 31	2005	2004	2003
Net gain on derivative instruments:			
Unrealized loss, net of taxes of $151.1 million	**$ (204.4)**	$ 7.0	$ 5.4
Reclassification adjustment for losses included in net income, net of taxes of $8.9 million	**(10.2)**	3.4	3.4
Net loss on derivative instruments	**(214.6)**	10.4	8.8
Translation adjustments	**(22.6)**	3.7	8.2
Registered pension alternate minimum liability (net of taxes of $9.1 million)	**(11.5)**	(0.6)	0.6
Other comprehensive (loss) income	**$ (248.7)**	$ 13.5	$ 17.6

The components of AOCI were:

Dec. 31	2005	2004	2003
Net loss on derivative instruments	**$ (275.4)**	$ (60.8)	$ (71.2)
Translation adjustments	**(52.7)**	(30.1)	(33.8)
Registered pension alternate minimum liabilities	**(13.2)**	(1.7)	(1.1)
Accumulated other comprehensive loss	**$ (341.3)**	$ (92.6)	$ (106.1)

VIII. Right of Offset Agreement

The corporation had a New Zealand bank deposit that had been offset with a New Zealand bank facility under a right of offset agreement. The arrangement did not qualify for offsetting under U.S. GAAP. During the second quarter of 2004, the corporation refinanced certain foreign operations and the bank deposit was used to settle the bank facility in full.

IX. Asset Retirement Obligations

Financial Accounting Standards Board (FASB) issued Statement 143, *Asset Retirement Obligations*, which requires asset retirement obligations to be measured at fair value and recognized when the obligation is incurred. A corresponding amount is capitalized as part of the asset's carrying amount and depreciated over the asset's useful life. TransAlta adopted the provisions of Statement 143 effective Jan. 1, 2003.

In accordance with Canadian GAAP, the asset retirement obligations standard was adopted retroactively with restatement of prior periods. Under U.S. GAAP, the impact of adopting Statement 143 was recognized as a cumulative effect of a change in accounting principle as of Jan. 1, 2003, the beginning of the fiscal year in which the Statement was first applied. The change resulted in an after-tax increase in net earnings of $52.5 million ($82.7 million pre-tax).

In March 2005, the FASB issued FASB Interpretation ("FIN") No. 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143". FIN No. 47 clarifies the term conditional asset retirement obligation as used in SFAS No. 143, "Accounting for Asset Retirement Obligations", and provides further guidance as to when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

Effective Dec. 31, 2005, TransAlta adopted the provisions of FIN No. 47. TransAlta's conditional asset retirement obligations ("ARO") relate to the possible future retirement of our Centralia coal-fired plant and Australian gas plants and related facilities and structures. TransAlta does not have a legal obligation to reclaim the site of the Centralia coal-fired plant, nor the Australian sites. If, however, TransAlta's customers in Australia close their respective sites, TransAlta must remove the existing plant from these sites. The ability to reasonably estimate a conditional ARO is a matter of management judgment, based on management's ability to reasonably estimate a settlement date or range of settlement dates, a method or potential method of settlement and probabilities associated with the potential dates and methods of settlement of its conditional AROs.

In accordance with the provisions of FIN No. 47, the Company has not recorded an asset retirement obligation associated with retirement of these facilities, given the uncertainty concerning the timing of future retirement, if any. The adoption of FIN No. 47 on Dec. 31, 2005 did not result in any impact to TransAlta's results of operations or financial position for the year ended Dec. 31, 2005, and the company does not expect the adoption to have a material impact on future results of operations, financial position or liquidity.

X. Limited Partnership Transaction

In 1998, the corporation transferred generation assets to its subsidiary TA Cogen. TA Power, an unrelated entity, concurrently subscribed to a minority interest in TA Cogen. The fair value paid by TA Cogen for the assets exceeded their historical carrying values. For Canadian GAAP, the corporation recognized a portion of this difference, to the extent it was funded by TA Power's investment in TA Cogen, as a gain. As TA Power held an option to resell their interest in TA Cogen to the corporation in 2018, this gain was originally being amortized in to income over this period. In 2003, TA Power's option to resell these units was eliminated and the unamortized balance of the gain was recognized in income.

Under U.S. Securities and Exchange Commission Staff Accounting Bulletin No. 51, the option initially held by TA Power to potentially resell TA Cogen units to the corporation in 2018 causes the excess of the consideration paid by TA Power over the corporation's historical carrying value in these assets to be characterized as contributed surplus in 1998. This amount of contributed surplus is reduced by the related tax effect. As a result, under U.S. GAAP, there is no amortization of the gain into income in the period from 1998 to 2002 and no recognition of the unamortized balance of the gain in 2003.

XI. Changes in Accounting Standards

On May 19, 2004, FASB issued FASB Staff Position (FSP) 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (the Act) that provides guidance on the accounting for the effects of the Act for employers that sponsor post-retirement health care plans that provide drug benefits. The Act introduces a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare. TransAlta's prescription drug benefit plan in the United States is not material to the corporation's post-retirement benefit plan and therefore the impact of the FSP is not material to the consolidated financial statements.

ELEVEN-YEAR FINANCIAL & STATISTICAL SUMMARY

(millions of Canadian dollars, except where noted)

Year ended Dec. 31	2005	2004	2003
FINANCIAL SUMMARY			
Earnings statement			
Revenues	**$ 2,838.5**	$ 2,838.3	$ 2,508.6
Operating income	**$ 441.2**	$ 478.1	$ 553.7
Net earnings applicable to common shareholders	**$ 198.8**	$ 170.2	$ 234.2
Balance sheet			
Total assets	**$ 7,740.7**	$ 8,133.0	$ 8,420.2
Short-term debt, net of cash and interest-earning investments	**$ (66.2)**	$ (102.7)	$ (35.2)
Long-term debt	**$ 2,605.0**	$ 3,057.9	$ 3,162.1
Preferred shares of a subsidiary	**$ –**	$ –	$ –
Other non-controlling interests	**$ 558.6**	$ 616.4	$ 477.9
Preferred securities	**$ 175.0**	$ 175.0	$ 450.8
Common shareholders' equity	**$ 2,543.1**	$ 2,472.7	$ 2,460.6
Total invested capital	**$ 5,809.2**	$ 6,519.3	$ 6,516.2
Cash flow			
Cash flow from operating activities	**$ 619.4**	$ 613.4	$ 756.5
Cash flow used in investing activities	**$ (242.1)**	$ (65.4)	$ (535.1)
Common share information (per share)			
Net earnings	**$ 1.01**	$ 0.88	$ 1.26
Dividends declared	**$ 1.00**	$ 1.00	$ 1.00
Book value (at year-end)	**$ 12.80**	$ 12.74	$ 12.90
Market price:			
High	**$ 26.66**	$ 18.75	$ 19.55
Low	**$ 17.67**	$ 15.25	$ 15.36
Close (TSX at Dec. 31)	**$ 25.41**	$ 18.05	$ 18.53
Ratios (percentage except where noted)			
Debt/invested capital	**43.6**	47.4	47.9
Return on common shareholders' equity	**7.5**	6.5	10.3
Return on invested capital	**7.4**	7.5	9.1
Cash flow to total debt	**23.5**	18.5	17.9
Cash flow to interest coverage	**4.8**	4.1	3.3
Dividend payout	**105.4**	120.0	79.0
Dividend yield	**3.9**	5.5	5.4
Price/earnings multiple	**26.7**	21.7	14.7
Weighted average common shares for the year (in millions)	**196.8**	192.7	185.3
Common shares outstanding at Dec. 31 (in millions)	**198.7**	194.1	190.7
STATISTICAL SUMMARY			
Number of employees	**2,657**	2,505	2,563
Generating capacity (net MW)[3]:			
Hydro	**802**	802	801
Coal	**4,885**	4,778	4,777
Gas	**1,933**	2,444	2,499
Renewables	**315**	313	245
Total generating capacity	**7,935**	8,337	8,322
Total generation production (GWh)[4]	**51,810**	54,560	53,134

* **Prior years have not been restated to conform with the current year's presentation.**

1 *2002 and 2001 Energy Marketing real-time trading contract revenues restated to be presented on a gross basis.*

2 *Includes discontinued operations.*

3 *Represents TransAlta's ownership.*

4 *Includes discontinued operations.*

Ratio Formulas

Debt/invested capital = (short-term debt + long-term debt – cash and interest-earning investments)/(debt + preferred securities + non-controlling interests + common equity)
Return on common shareholders' equity = net earnings excluding gain on discontinued operations/average of opening and closing common equity

2002	2001	2000	1999	1998	1997	1996	1995
$ 1,814.9[1]	$ 2,559.5[1]	$ 1,587.0	$ 1,029.4	$ 1,089.9	$ 1,656.4	$ 1,515.6	$ 1,330.5
$ 223.9[2]	$ 468.9[2]	$ 604.6[2]	$ 442.0[2]	$ 660.1[2]	$ 586.6	$ 570.6	$ 591.4
$ 189.9	$ 214.6	$ 279.8	$ 170.1	$ 211.4	$ 182.6	$ 181.0	$ 181.7
$ 7,419.6	$ 7,877.9	$ 7,627.1	$ 6,038.4	$ 5,392.6	$ 4,882.2	$ 4,804.4	$ 4,346.9
$ 146.7	$ 475.2	$ 220.5	$ (173.6)	$ (149.4)	$ (20.3)	$ 13.3	$ 1.3
$ 2,706.6	$ 2,511.1	$ 2,201.4	$ 2,177.4	$ 1,903.6	$ 2,198.0	$ 2,364.0	$ 2,009.0
$ –	$ –	$ 121.6	$ 268.3	$ 268.4	$ 267.6	$ 270.5	$ 371.9
$ 263.0	$ 281.0	$ 253.4	$ 377.4	$ 503.3	$ 162.9	$ 164.4	$ 73.3
$ 451.7	$ 452.6	$ 292.0	$ 287.1	$ –	$ –	$ –	$ –
$ 2,039.6	$ 1,989.7	$ 1,957.4	$ 1,835.6	$ 1,855.0	$ 1,594.3	$ 1,582.3	$ 1,542.7
$ 5,607.6	$ 5,709.6	$ 5,046.3	$ 4,772.2	$ 4,380.9	$ 4,202.5	$ 4,394.5	$ 3,998.2
$ 437.7	$ 715.6	$ 188.7	$ 422.0	$ 470.7	$ 666.4	$ 563.2	$ 430.7
$ (36.2)	$ (1,076.9)	$ (205.0)	$ (988.8)	$ (137.2)	$ (319.7)	$ (459.9)	$ (361.3)
$ 1.12	$ 1.27	$ 1.66	$ 1.00	$ 1.31	$ 1.14	$ 1.14	$ 1.14
$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 0.99	$ 0.98	$ 0.98	$ 0.98
$ 12.01	$ 11.82	$ 11.61	$ 10.85	$ 10.94	$ 9.96	$ 9.92	$ 9.71
$ 23.95	$ 30.13	$ 22.55	$ 25.15	$ 25.40	$ 22.75	$ 18.20	$ 14.88
$ 16.69	$ 19.15	$ 13.20	$ 12.25	$ 18.20	$ 15.10	$ 14.25	$ 13.00
$ 17.11	$ 21.60	$ 22.00	$ 14.15	$ 22.60	$ 22.55	$ 17.25	$ 14.63
50.9	52.3	48.0	45.6	40.0	51.8	54.1	50.3
3.5	10.9	11.7	9.2	12.3	11.5	11.6	11.9
4.0	8.7	12.3	9.7	15.4	13.7	13.6	15.5
16.1	21.8	25.3	21.7	22.8	22.0	22.1	24.0
3.8	–	–	–	–	–	–	–
241.8	78.5	75.8	99.7	75.8	85.7	86.2	85.7
5.8	4.6	4.6	7.1	4.4	4.4	5.7	6.7
41.7	17.3	16.7	14.2	17.3	19.8	15.1	12.8
169.6	169.0	168.8	169.5	161.3	159.7	159.2	158.9
169.8	168.3	168.6	169.2	169.6	160.0	159.5	158.9
2,573	2,656	2,363	2,679	2,455	2,667	3,099	2,128
801	800	800	800	800	800	800	800
4,966	5,090	5,016	3,676	3,676	3,676	3,676	3,676
1,333	1,108	1,054	1,464	1,008	832	815	485
44	–	–	–	–	–	–	–
7,144	6,998	6,870	5,940	5,484	5,308	5,291	4,961
46,877	44,136	40,644	37,771	39,001	36,401	34,264	33,373

Return on invested capital = earnings before non-controlling interests, income taxes and net interest expense/average annual invested capital

Cash flow to total debt = cash flow from operations before changes in working capital/two-year average of total debt

Dividend payout = dividends/net earnings excluding gain on discontinued operations

Dividend yield = common share dividends/current year's close price

Price/earnings multiple = current year's close/basic earnings per share from continuing operations

ANNUAL MEETING

The Annual Meeting will be held at
1 p.m. EST on Thursday, April 27, 2006
at Le Royal Meridien King Edward Hotel,
Vanity Fair 'A' Ballroom,
37 King Street East, Toronto, Ontario

TRANSFER AGENT

CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Station
Toronto, Ontario M5C 2W9

Phone
North America:
1.800.387.0825 toll-free
Toronto/outside North America:
416.643.5500

E-mail
inquiries@cibcmellon.com

Fax
416.643.5501

Website
www.cibcmellon.com

EXCHANGES

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

TICKER SYMBOLS

TransAlta Corporation common shares:
TSX: TA NYSE: TAC
TransAlta Corporation preferred securities:
TSX: TA.Pr.C

VOTING RIGHTS

Common shareholders receive one vote
for each common share held

ADDITIONAL INFORMATION

Requests can be directed to:
Investor Relations
TransAlta Corporation
P.O. Box 1900, Station "M"
110 - 12th Avenue S.W.
Calgary, Alberta T2P 2M1

Phone
North America:
1.800.387.3598 toll-free
Calgary/outside North America:
403.267.2520

E-mail
investor_relations@transalta.com

Fax
403.267.2590

Website
www.transalta.com

SPECIAL SERVICES FOR REGISTERED SHAREHOLDERS

Service	Description
Dividend reinvestment and share purchase plan*	Conveniently reinvest your TransAlta dividends and purchase common shares without brokerage costs
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax slips and dividends without the delays resulting from address and ownership changes

To use these services please contact our transfer agent.

* *Also available to non-registered shareholders.*

STOCK SPLITS AND SHARE CONSOLIDATIONS

Date	Events	Ratio
May 8, 1980	Stock split	3:1
Feb. 1, 1988	Stock split [1]	2:1
Dec. 31, 1992	Reorganization – TransAlta Utilities shares exchanged for TransAlta Corporation shares [2]	1:1

The valuation date value of common shares owned on Dec. 31, 1971, adjusted for stock splits, is $4.54 per share.

1 *The adjusted cost base for shares held on Jan. 31, 1988 was reduced by $0.75 per share following the Feb. 1, 1988 share split.*

2 *TransAlta Utilities Corporation became a wholly-owned subsidiary of TransAlta Corporation as a result of this reorganization.*

DIVIDEND POLICY

In declaring dividends, the directors consider several factors, including the corporation's earnings, cash flow, capital requirements and the expectations of shareholders.

IMPORTANT DIVIDEND DATES

Payment Date	Record Date	Ex-Dividend Date
April 1, 2005	March 1, 2005	Feb. 25, 2005
July 1, 2005	June 1, 2005	May 30, 2005
Oct. 1, 2005	Sept. 1, 2005	Aug. 30, 2005
Jan. 1, 2006	Dec. 1, 2005	Nov. 29, 2005
April 1, 2006	March 1, 2006	Feb. 27, 2006

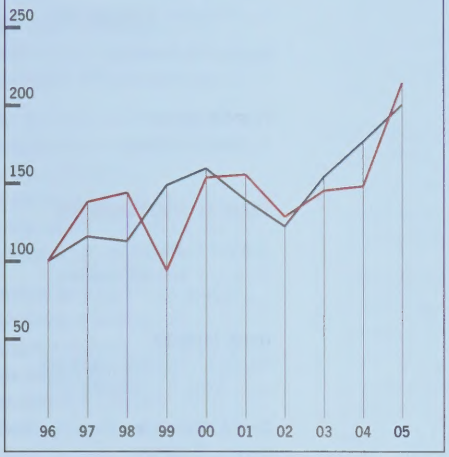
Dividends are paid on the first of the month in January, April, July and October. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

SUBMISSION OF CONCERNS REGARDING ACCOUNTING OR AUDITING MATTERS

In 2002, TransAlta adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or auditing matters on an anonymous, confidential basis to the Audit and Environment Committee of the Board of Directors. Such submissions may be directed to the Audit and Environment Committee c/o the Corporate Secretary of the corporation.

TOTAL SHAREHOLDER RETURN VS. S&P/TSX COMPOSITE INDEX

(Years ended Dec. 31)

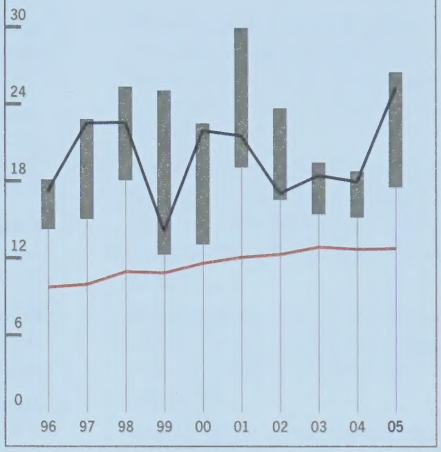


	96	97	98	99	00	01	02	03	04	05
TransAlta	100	138	144	94	154	156	129	146	149	**216**
S&P/TSX Composite Index	100	116	113	149	160	140	123	155	178	**202**

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 1996 would be worth today, assuming the reinvestment of all dividends.

TEN-YEAR TRADING RANGE & MARKET VALUE VS. BOOK VALUE

($ per share)

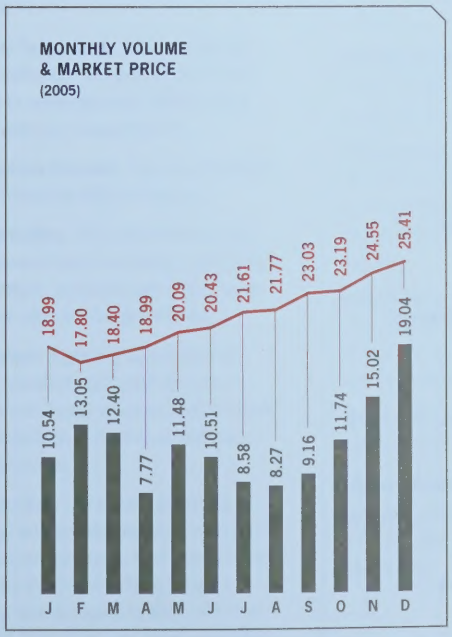


	96	97	98	99	00	01	02	03	04	05
Market Value	17.25	22.55	22.60	14.15	22.00	21.60	17.11	18.53	18.05	**25.41**
Book Value	9.71	9.94	10.94	10.85	11.61	12.08	12.32	12.90	12.74	**12.80**

Trading Range

MONTHLY VOLUME & MARKET PRICE

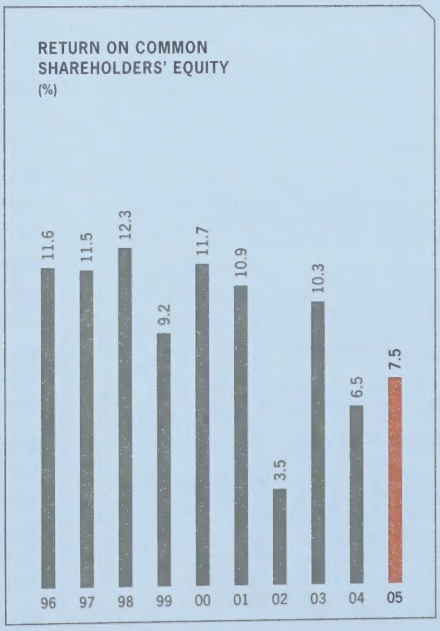
(2005)



Volume (millions of shares) — TSX Market Price ($ per share)

RETURN ON COMMON SHAREHOLDERS' EQUITY

(%)



TRANSALTA CORPORATION OFFICERS

Stephen G. Snyder
President &
Chief Executive Officer

Ian A. Bourne
Executive Vice-President

Brian Burden
Executive Vice-President &
Chief Financial Officer

Linda K. Chambers
Executive Vice-President,
Generation Technology &
Supply Chain Management

Frederick M. Gallagher
Executive Vice-President,
Gasification

Richard P. Langhammer
Executive Vice-President,
Generation Operations

Thomas M. Rainwater
Executive Vice-President,
Corporate Development &
Marketing

Ken Stickland
Executive Vice-President,
Legal

Michael Williams
Executive Vice-President,
Human Resources &
Communications

Gregory Wilson
Senior Vice-President &
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2005 CHANGES

Ian Bourne retired as Executive Vice-President & Chief Financial Officer in 2005. Ian remains part of TransAlta's leadership team.

Robert Soeldner, officer of TransAlta Corporation, left in 2005.

In an effort to be environmentally responsible, please notify your financial institution to avoid duplicate mailings of this annual report.

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Air Emissions Substances released to the atmosphere through industrial operations. For the fossil fuel-fired power sector, the most common air emissions are sulphur dioxide, oxides of nitrogen, mercury and greenhouse gases.

Alberta PPA Alberta power purchase arrangement borne through legislation to separate generator from the market.

Availability A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Boiler A device for generating steam for power, processing or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

Brownfield Development A previously constructed electric power generating facility.

Btu (British Thermal Unit) A measure of energy. The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit, when the water is near 39.2 degrees Fahrenheit.

Capacity The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

Clean Coal Technology New technologies such as gasification using solid fuels (coal and coke) to produce power and chemical products with very low emissions.

CO_2 Emissions Intensity Amount of carbon dioxide emitted per MWh produced.

Coal Gasification The conversion of solid fuel to gaseous form, for subsequent conversion into power, synthetic gas, hydrogen or a variety of other chemical products.

Cogeneration A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes.

Combined Cycle An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Derate To lower the rated electrical capability of a power generating facility or unit.

Flue Gas Desulfurization Unit (Scrubber) Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Force Majeure Literally means "greater force." These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Geothermal Plant A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigajoule (GJ) A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 Btu.

Gigawatt (GW) A measure of electric power equal to 1,000 megawatts.

Gigawatt Hour (GWh) A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenfield Development A new electric power generating facility built from the ground up on a new site.

Greenhouse Gas (GHG) Gases having the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide and hydrofluorocarbons.

Heat Rate A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

Megawatt (MW) A measure of electric power equal to 1,000,000 watts.

Megawatt Hour (MWh) A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Net Maximum Capacity The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

Power Purchase Arrangement (PPA) A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA buyers.

Peaking Plant A plant usually housing old, low-efficiency steam units, gas turbines, diesels or pumped-storage hydroelectric equipment normally used during the peakload periods.

Renewable Power Power generated from renewable terrestrial mechanisms including wind, geothermal, solar and biomass with regeneration.

Reserve Margin An indication of a market's capacity to meet unusual demand or deal with unforeseen outages/shutdowns of generating capacity.

Spark Spread A measure of gross margin per MW (sales price less cost of fuel).

Target Zero TransAlta's initiative designed to drive improvements in safety and environmental performance, where zero lost-time and medical aid incidents and environmental incidents causing damage to the environment do not occur.

Turbine A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Turnaround Periodic planned shutdown of a generating unit for maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back online.

Unplanned Outage The shutdown of a generating unit due to unanticipated breakdown.

Value At Risk (VAR) A measure to manage earnings exposure from trading activities.

TransAlta™*

TransAlta Corporation

Box 1900, Station "M", 110 – 12th Avenue SW, Calgary, Alberta, Canada T2P 2M1 Ph: 403.267.7110 www.transalta.com